TRANSCRIPT OF RECORD

Supreme Court of the United States

OCTOBER TERM, [redacted] 1962

No. [redacted] 72

WISCONSIN, ET AL., PETITIONERS,

vs.

FEDERAL POWER COMMISSION, ET AL.

No [redacted] 73

CALIFORNIA, ET AL., PETITIONERS,

vs.

FEDERAL POWER COMMISSION, ET AL.

No. [redacted] 74

LONG ISLAND LIGHTING CO., ET AL.,
PETITIONERS,

vs.

FEDERAL POWER COMMISSION, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

FILED FEBRUARY 28, 1962
CERTIORARI GRANTED MAY 14, 1962

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IN THE

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 16,175

STATE OF WISCONSIN and PUBLIC SERVICE COMMISSION OF WISCONSIN, *Petitioners*

v.

FEDERAL POWER COMMISSION, *Respondent*

No. 16,177

LONG ISLAND LIGHTING COMPANY, PHILADELPHIA ELECTRIC COMPANY and THE UNITED GAS IMPROVEMENT COMPANY, *Petitioners*

v.

FEDERAL POWER COMMISSION, *Respondent*

No. 16,180

PEOPLE OF THE STATE OF CALIFORNIA and PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, *Petitioners*

v.

FEDERAL POWER COMMISSION, *Respondent*

On Petition to Review Order of the Federal Power Commission

JOINT APPENDIX

EXCERPTS FROM TRANSCRIPT OF PROCEEDINGS

6331

William H. Lyon

was called as a witness, and, having been first duly sworn, was examined and testified as follows:

6332

Direct Examination

By Mr. Lamb:

. . . . . .

6347

This does not however, mean that the BTU method is unsatisfactory as a cost denominator. It simply means that the relationship between costs and BTU's should be examined in more detail. It may be that with a proper adjustment multiplier for oil, the BTU approach will serve. Among the factors affecting such an adjustment are the following: The area that a gas well drains is many times that of an oil well. Differences in the optimum rate of production is a factor in this spacing, but reservoir performance is different in the case of each product.

In the case of Phillips, gas well spacing averages one well per 520 acres whereas oil well spacing averages one well per 20 acres. Next where the hydrocarbons are oil, the BTU content will be 3 to 5 times that where it is gas and this ratio changes with the gas pressure in the reservoir. Both reservoir content factors are modified by recovery factors with that of gas around 80 percent while that of oil is around 50.

Deeper reservoirs mean higher per well cost for either product, though we do not know yet to what extent this is offset by higher per well recoveries.

The net effect of these variables on relative production

costs will require some further study. Present indications are that if an overall adjustment factor can be developed to employ the BTU method, it will be to multiply the BTU's of oil by a

6348

factor of somewhere between 4 and 6 before allocating costs.

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7853

Dan L. Mayer

was called as a witness, being first duly sworn, was examined and testified as follows:

Direct Examination

By Mr. Heady:

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7876

Q. When you speak of casinghead gas contracts, are you referring to a particular contract, or to a type of contract which is in general use? A. I am referring to a form or type of contract which is adapted to fit the needs of a situation peculiar to casinghead gas. The term "casinghead gas contract" is a term which is generally understood in the industry, and denotes the general type of provisions contained in the contract as distinguished from the specific provisions.

The most outstanding feature of the casinghead gas contract is that it does not provide a specific price per Mcf.

Q. What are the conditions under which the casinghead gas type of contract is used and what in general is the nature of the provisions in such contracts. A. The casinghead gas contract is a type of contract

which was developed over a period of years in the industry to meet the particular necessities of handling casinghead gas. It is essentially an agreement whereby the producer participates in the proceeds received by the gasoline plant operator who is the purchaser, rather than an agreement by the purchaser to pay a specified amount per Mcf. The gasoline plant operator agrees to pay an amount for the gas which is the sum of two calculations. One calculation is based on the test gasoline content contained in the gas, the amount so determined being related to both the quantity of test gasoline in the gas, and the current market price of natural gasoline and other liquids extracted.

The other calculation is a percentage of the proceeds received by the gasoline plant operator from such portion of the residue gas as the plant operator has available, and is able to sell.

The various forms of casinghead gas contracts in actual use will differ in their specific provisions, and in their methods of computation, but in general the different forms of casinghead gas contract are merely variations of the two computations based on test gasoline content and residue proceeds.

Q. What percentage of the proceeds from the sales of residue gas by the gasoline plant operator is paid to the producer? A. That percentage will vary among the different forms of casinghead gas contract, but it usually runs between 50 and

75 percent. Two forms of contract developed by the Natural Gasoline Association of America provide for 50 percent of the proceeds. These particular forms are in such common use that printed forms can be purchased

from almost any printing establishment operating in a producing area.

The form of contract generally used by Phillips provides for payment to the producer of 50 percent of the first 2.6798 cents per Mcf received and 66⅔ percent of all above that. This averages something in excess of 60 percent of the residue proceeds received by Phillips. If there are any added costs of handling the residue gas, as for boosting, treating or dehydrating, the casinghead gas contracts usually provide for a deduction of those costs before applying the stated percentage to the proceeds.

Q. Is there any particular reason for the participating features of these contracts? A. Yes, the participating character of these contracts is an essential to the purchase and sale of casinghead gas, because casinghead gas is produced with oil and controlled by the amount of oil production it is subject to fluctuation in volumes of production. This is contrasted with production from a gas field, which is controlled by market demand for gas.

Another important factor is that the producer may need all or substantially all of the residue gas for his lease operations. This need of the producer for the return of the residue gas has

7879

always been recognized in the contracts, themselves, which provide that the producer may have all or any part of the residue returned for lease operation, if he wants it. Each of these conditions make it difficult for the gasoline plant operator to know how much residue gas he will have available for sale, yet to meet the needs of the producers, the gasoline plant operator has to agree to take the casinghead gas and process it.

7880

One of the most variable factors affecting the value

of and, therefore, the price paid for casinghead gas is the gasoline content. This varies from field to field, and from well to well within the same field, and is dependent upon many things, including gas-oil ratio, temperature and separation pressure. Respecting the effect of temperature, considerable seasonable variation is experienced. For this reason, content tests are usually conducted quarterly.

An inspection of a summary of all casinghead gas contract content tests for Phillips' plants shows a range from .158 gallons per thousand cubic feet to 13.6 gallons per thousand cubic feet.

Because of all of these variable factors, the participating features of these contracts were developed whereby the plant operator agrees that he will pay an amount based on the gasoline content, and, if there is any residue left which the producers do not want returned and the plant operator is able to sell it, a percentage of what the plant operator gets for it.

This type of contract has worked very satisfactorily for over 25 years.

Q. In your opinion, would it be practical for a producer such as Phillips to charge specific rates for sales of gas to gasoline plants which are now being made under the casinghead gas type of contract? A. In my opinion, it would not be practical to do so. As

I have stated, the casinghead gas contract was originally developed to meet the needs of a peculiar situation. The fact that casinghead gas sales may now be subject to regulation does not eliminate the practical considerations which brought about the use of casinghead gas contracts in the first place. I do not believe that specific rates for casinghead gas could be used with any degree of success.

Q. Do you believe that it would be practical to charge a specific rate applicable to that portion of the residue gas which remains after processing, and return to leases and is available for sale by the purchaser? A. No.

Q. Why do you reach that conclusion? A. The purchaser under the casinghead gas contract agrees to purchase all of the gas, whether or not he has a market for all of the residue. Since the volumes of residue gas available for sale vary both with the production of raw gas and with the amount returned to leases, the purchaser might be forced into paying for gas for which he had no market.

The changes in the volume of residue gas available for sale and the volumes which can be sold can change abruptly, without notice, and the gasoline plant operator would assume an unjust and uneconomic burden if he were forced to pay a specific price for gas, for all residue gas available for sale.

* * * * * * * * * * *

8445

Lloyd Cramer

was called, and having been previously duly sworn, was

8446

examined and testified further as follows:

Further Direct Examination

By Mr. Heady:

* * * * * * * * * * *

8486

Q. I notice that in both your Exhibits 282 and 283, you have used costs and revenues as of January 1, 1956, whereas Exhibit 223, prepared by Mr. Mayer, includes revenues under rates proposed by Phillips as of November 1, 1956.

Can you reconcile the cost and revenue figures which you have used with the higher revenues shown by Mr. Mayer? A. Yes, Exhibits 282 and 283 were first—since Exhibits 282 and 283 were first prepared, the Commission has at various times ordered the rate increases proposed by Phillips to Panhandle Eastern Pipeline Company in docket Nos. G-10883 and G-11125, to Michigan-Wisconsin Pipeline Company in Docket No. G-10793, and to El Paso Natural Gas Company in Docket G-11217 to be consolidated with this proceeding. It was not possible within the time that was available to revise these exhibits—that is Exhibit 282 and Exhibit 283, to show the effect of the additional increases proposed by Phillips.

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13558

Edward L. Dunn

resumed the stand and, having been previously duly sworn, was examined and testified as follows:

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13573

Further Cross-Examination

By Mr. Heady:

Q. Mr. Dunn, you referred, as I recall, to the fact that in El Paso's recent rate filing, it anticipated the contractual increases which were to become effective January 1, 1958, and included that as a part of its costs in the rate filing. Is that correct? A. That is correct.

Q. In any rate filing made by El Paso, did El Paso ever include the effect of the contractual increase to Phillips so that if El Paso got the rates which it had filed for, those rates would then include the increase to Phillips, and there would be no need for any further change in El Paso's rates? A. In one filing, it did. That

was Docket G-2018, because, as you will recall, there was an agreement reached as to what the rate would be under that docket. That was included in the filing in Docket G-2018.

13574

Q. That is the only time it ever was done? A. The next filing, Docket G-4769, it was not done.

Q. You would agree mathematically it could be done, so that when the Commission grants the rate to El Paso there would be no further change in El Paso's rates? A. I would agree that, mathematically, it could be done. As to what the effect would be with respect to further changes in El Paso's rates for other factors, that would be another matter.

Mr. Heady: That is all I have.

Mr. Lamb: Mr. Examiner, I have another question as a result of that.

Further Cross-Examination

By Mr. Lamb:

Q. You said mathematically it could be done, Mr. Dunn. Well, just how, in actuality, could it be done? Could you come to the Commission representing El Paso and say, "Well, if we get a rate increase, it is going to have to include something that we haven't paid out yet, but contractually we may have to pay out next year." Is that the way it would be presented to the Commission? A. Yes. And that is done many times, sir.

As a matter of fact, that is the way Pandhandle Eastern files.

Q. Well, how was this agreement made that you referred

13575

to when you answered Mr. Heady's question? You said some agreement was made in what, 2018, Docket G-2018? A. Yes.

(13575)

Q. Who was the agreement made by? A. Mr. Paul Kayser, with Phillips.

Q. And it was presented to the Commission on that basis?

13576

A. Yes.

Q. And how was it handled then, do you know? A. Well, the Commission allowed it.

* * * * * * * * * * *

16984

Oral Argument

* * * * * * * * * * *

Mr. Torkelson: [Counsel for Wisconsin] Now, we finally, in the limited time available, we do want to make a brief comment about this matter of system-wide versus area rates.

In this case, as the Commission is aware, we made a motion for the purpose of obtaining additional evidence on this subject, namely, so that there would be an additional-- I am sorry.

Mr. Reese: Mr. Chairman, if it would be possible, I would be happy to yield enough time to Mr. Torkelson to finish that point, if he wanted to.

The Chairman: All right. You have ten minutes, do you?

16985

Mr. Reese: Yes, sir.

The Chairman: Go ahead, Mr. Torkelson.

Mr. Torkelson: I will take five minutes of it.

This motion together with a similar staff motion was made for the purpose of obtaining additional evidence for the record to show costs in the various areas for the purpose of attempting to have rate making rather than on a system-wide basis, possibly on a location or area basis, and I am using the term "location" or "area" in a very general way.

Those motions, of course, were denied.

And on the basis of the record as made in this case there was, of course, the problem for the Examiner as to what to do under the circumstances. Phillips urged and the Examiner adopted the so-called system-wide or postage stamp approach and under the record, while we do not agree in principle that that is correct, still for purposes of this case, if this Commission wishes to apply this so-called postage stamp principle, based on the actual cost of service, that on the basis of that record we would not object and we feel that this is a possible solution to this problem.

Another possible solution is to adopt the cost of service and then order Phillips to file within a reasonable time tariffs or rates to return to it revenues which would cover that cost of service in the amount indicated.

Now, this is a method that is followed quite commonly by

regulatory Commissions. We understand that it was followed in Natural Gas Pipeline Company of America case decided back sometime about 1940 and, of course, is a method that your Wisconsin Commission frequently follows in prescribing rates.

Commissioner Connole: Would that be suited for independent producer situations, Mr. Torkelson?

Mr. Torkelson: We think it could be. We recognize there is a certain amount of flexibility there, but we think it could be worked out, and I am merely stating some broad principles.

Commissioner Connole: What would they properly do, file a rate, for example, for gas in the XYZ field or the ABC area and that would be the price for gas, just the way a transportation company files upstairs here, a rate for transportation of apples between Madison and Chicago. Is that the idea?

(16986)

Mr. Torkelson: Well, they would file a rate, but it would be a little bit different, I believe, because as we see it, that rate, together with other rates, would produce in the aggregate revenues which would equal a cost of service for Phillips.

Commissioner Connole: Even applicable then to future sales, future contracts not yet entered into?

Mr. Torkelson: Well, on that, which is a question that was raised this morning, our suggestion—and it is again on a very broad basis—would be that if the new sales should be in a location which would be, one might say reasonable within

16987

the scope of the existing area where they are doing business and making sales, then our thought was that it is possible to apply that rate to the future sales. On the other hand, if you should have sales or deliveries made in an entirely new area, remote, divorced, or for some other reason, then there probably would have to be a filing of some kind or a prescription of a rate in the light of that particular circumstance. I think that—

Commissioner Connole: Have you given any real serious thought as to whether that is the way to price natural gas or whether you should continue on a contract-by-contract basis?

Mr. Torkelson: I can't claim to be an expert on this and I wouldn't want to be understood to be an expert, because I think that we are getting into the field where rate people should be consulted rather than—

Commissioner Connole: Rather than lawyers?

Mr. Torkelson: Yes, sir. Thank you very much.

Commissioner Connole: Mr. Torkelson, I guess it just follows from the whole approach you take that we should then regulate each and every producer in the same manner as you are advocating for Phillips?

Mr. Torkelson: That is a broad question, Your Honor. In principle I believe that is true, but I also believe and I think we have indicated in certain length [circumstances] that we would not

16988

object in principle to certain small producers which involve small volumes of gas having a different treatment.

When this Commission had the general investigation of how to fix producer rates sometime ago—and I do forget the docket number, but I am sure everybody recalls it—I think we made that proposal. We indicated that there might be a different treatment for what we might call a smaller producer.

Commissioner Stueck: But supposing you had three big producers operating on a unitized basis and each one having a different cost of service? Would you reconcile yourself to charging three different prices for the same gas coming out of the same hole?

Mr. Torkelson: I believe this Commission has faced up to that situation in certain cases and—

Commissioner Stueck: That would be a variation, of course, from your theory?

Mr. Torkelson: Not necessarily.

Thank you very much.

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(18622)

[18425 on facing page]

18622

Exhibit No. 282

CRAMER 2/15/57

PHILLIPS PETROLEUM COMPANY AND SUBSIDIARY COMPANIES
JURISDICTIONAL NATURAL GAS OPERATIONS

Pro Forma Statement of Cost of Service and Deficiency in Earnings
Based on Year 1954

	Amount	MCF Volume	Per MCF
	(a)	(b)	(c)
Cost of service-jurisdictional sales from systems	$68,568,876.42		
Cost of service-jurisdictional sales from leases	13,094,498.59		
Sub-total	81,663,375.01		
Regulatory commission expense	400,000.00		
Total cost of service-jurisdictional sales of gas	82,063,375.01		16.707¢
Revenue from jurisdictional sales	45,568,291.02		9.277¢
Deficiency in earnings	36,495,083.99		7.430¢
Total jurisdictional sales—MCF @ 14.65 psia		491,178,953	

Docket G1148 et al
Exhibit
Page 1

18425

Exhibit No. 215-A

PHILLIPS PETROLEUM COMPANY DOCKET NO. G-1148
Indicated Rates Compared With Book Revenues, Present Rates and Cost
All Areas

No. Line	Particulars	1954 Sales Volumes MCF @ 14.65#	1954 Revenues Per Books		Revenues on 1954 Sales Volumes at July 1, 1956 Rates		1954 Allocated Cost of Service		Revenues on 1954 Sales Volumes at Indicated Rates		Increase (Decrease) of Revenues Under Indicated Rates Over			Remarks
			Amount	Avg. Rate	Amount	Avg. 7-1-56 Rates	Amount	Avg. Cost	Amount	Cents/ MCF	Per Books	7-1-56 Rates	Cost	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Panhandle Areas													
1	Wellhead Sales—Dry Gas	10151656	$ 323793	3.19¢	$ 401667	3.957¢	$ 890595	8.7729¢	$ 886158	8.73¢	$562365	$ 484491	$(4437)	
2	Wellhead Sales—Csghd. Gas—Specific	197051	8434	4.28	8921	4.527	17287	8.7729	16763	8.51	8329	7842	(524)	
3	Gathering System Sales	13556716	1873314	13.82	1885365	13.907	1506843	11.1151	1490769	11.00	(382545)	(394596)	(16074)	
4	Residue System Sales	280541682	25596542	9.12	27472962	9.793	26230928	9.3501	26273869	9.37	677327	(1199093)	42941	
5	Total	304447105	27802083	9.13	29768915	9.778	28645653	9.4091	28667559	9.42	865476	(1101356)	21906	
	Permian Basin Area													
6	Residue System Sales	111778499	8460752	7.57	8679344	7.765	9410744	8.4191	9389394	8.40	928642	710050	(21350)	
	Miscellaneous													
7	Wellhead Sales—Dry Gas	13721169	1285508	9.37	1366534	9.959	5037987	36.7169	5037987	36.72	3752479	3671453	0	
8	Wellhead Sales—Csghd. Gas—Specific	14842126	1331572	8.97	1697916	11.440	1302084	8.7729	1298686	8.75	(32886)	(399230)	(3398)	
9	Wellhead Sales—Csghd. Gas—Percentage	12588114	692166	5.50	692166	5.499	927945	7.3716	944110	7.50	251944	251944	16165	
10	Residue System Sales	24968617	2533380	10.15	2659805	10.653	2096838	8.3979	2099722	8.41	(433658)	(560083)	2884	
11	Total	66120026	5842626	8.84	6416421	9.704	9364854	14.1634	9380505	14.19	3537879	2964084	15651	
12	Total All Areas	482345630	$42105461	8.73¢	$44864680	9.301¢	$47421251	9.8314¢	$47437458	9.83¢	$5331997	$2572778	$ 16207	

26148

Docketed Oct. 28, 1948

100-2 Formal

Docket No. G-1148

Order Instituting Investigation

Upon consideration of the Commission's official files and the public records of other federal agencies pertaining to Phillips Petroleum Company (hereinafter referred to as "Respondent"), a Delaware corporation with principal executive offices at 80 Broadway, New York 5, New York, and Phillips Building, Bartlesville, Oklahoma;

It appears to the Commission that:

(a) Respondent is engaged, among other things, in the production, purchase, gathering, transportation and sale of natural gas in the State of Arkansas, Kansas, New Mexico, Oklahoma, and Texas;

(b) Respondent reports that it owns and operates approximately 3,800 miles of gathering, residue, and other gas lines located in the States designated above, together with various compressor or booster stations and appurtenant facilities;

(c) In this Commission's Opinion In the Matter of Michigan-Wisconsin Pipe Line Company, January 17, 1947, 6 F.P.C. 1, 67 P.U.R. (N.S.) 427, we stated therein with respect to the motion filed by the City of Detroit on October 11, 1946, for an order requiring Respondent herein to be made a party to the proceeding in Docket No. G-669:

"We believe that whether Phillips is or is not a natural gas company cannot properly be determined in this proceeding. If such determination is required it should be made a separate case after a thorough investigation of Phillips' operations and we therefore find that the motion of the City of Detroit should be dismissed."

(d) By its letters of June 19, August 15, September 6, 1940, April 3, 1941, and August 3, 1943, to this Commission, Respondent has disclosed that it is or will be a natural-gas company within the meaning of that term as used in the Natural Gas Act;

(e) In 1947, Respondent reported to the Securities and Exchange Commission, with respect to its sale of natural gas to purchasers which transport and sell the gas in interstate commerce, that "Although such sales and the transportation of natural gas antecedent thereto constitute operations by the Company as a 'natural gas company' under the Natural Gas Act, and, as such, are subject to the Federal Power Commission's jurisdiction, unless the exercise of such jurisdiction constitutes an interference with state regulation of production and gathering, the Commission with Commissioner Draper dissenting in a a declaration made on the 15th day of August, 1947, disclaimed the intention to exercise jurisdiction over such sales if made at arm's length, that is, sales made as an incident to the producing or gathering operation by a producer or gatherer of gas to a non-affiliate (Order No. 139, Docket No. R-106)";

(f) By reason of its operations, facilities, and sales of natural gas to purchasers which transport and resell

such gas in interstate commerce for ultimate public consumption, Respondent may be a natural-gas company subject to the jurisdiction of the Commission;

The Commission finds that:

It is necessary and proper, in the public interest, that an investigation be instituted by the Commission, upon its own motion:

(1) To determine whether Respondent is a natural-gas company within the meaning of the Natural Gas Act; and

(2) Into and concerning all rates, charges, or classifications demanded, observed, charged or collected by Respondent in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, and any rules, regulations, practices, or contracts affecting such rates, charges, or classifications;

The Commission, upon its own motion, orders that:

An investigation of Respondent, Phillips Petroleum Company, be and hereby is instituted for the purpose of enabling the Commission:

(A) To determine with respect to the Respondent:

(i) Whether it is a natural-gas company within the meaning of the Natural Gas Act; and

26150

(ii) Whether, in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged, or collected, or any rules, regulations, practices or contracts affecting such rates, charges, or classifica-

tions are unjust, unreasonable, unduly discriminatory, or preferential; and

(B) If it shall find, after hearing, that the Respondent is a natural-gas company within the meaning of the Natural Gas Act, and that any of Respondent's rates, charges, classifications, rules, regulations, practices, or contracts, subject to the jurisdiction of the Commission, are unjust, unreasonable, unduly discriminatory, or preferential, to determine and fix by order or orders just and reasonable, nondiscriminatory or non-preferential rates, charges, classifications, rules, regulations, practices, or contracts to be thereafter observed and in force.

By the Commission.

Date of Issuance: October 29, 1948

* * * * * * * * * * *

32909, 32911, 32919

[Extract from opinion of May 22, 1953 in No. 11,247—USCA-DC, *State of Wisconsin and Public Service Commission of Wisconsin* v. *Federal Power Commission,* is printed at pages 405 to 406 of this Joint Appendix.]

32929

[Judgment and Decree of May 22nd, 1953 in above-captioned case is printed at page 406 of this Joint Appendix.]

32931-32932

[Commission Order Vacating Termination of Proceedings and Continuing Investigation issued November 22, 1954 is printed at pages 407 to 409 of this Joint Appendix.]

30467

Docket No. G-1148

Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883 and G-10359

Order Consolidating Proceedings and Fixing Date of Hearing

(Issued May 28, 1956)

By order issued October 29, 1948, in Docket No. G-1148, the Commission instituted an investigation of Phillips Petroleum Company (Phillips) to determine (1) whether it is a natural-gas company within the meaning of the Natural Gas Act, and (2) whether, in connection with any transportation or sale of natural gas by such company, subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged or collected, or any rules, regulations, practices or contracts affecting such rates, charges, or classifications are unjust, unreasonable, unduly discriminatory, or preferential.

In its opinion issued August 22, 1951,[1] the Commission found, inter alia, that Phillips was not a natural-gas company within the meaning of Sections 1(b) or 2(6) of the Natural Gas Act, and by order accompanying that opinion the Commission terminated the investigation proceeding instituted by its order of October 29, 1948. Thereafter, the United States Court of Appeals for the District of Columbia Circuit handed down its opinion[2] reversing the Commission and determined that Phillips is a natural-gas company

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[1] In the Matter of Phillips Petroleum Company, Docket No. G-1148, Opinion No. 217 and accompanying order, 10 F.P.C. 246, 283.

[2] *State of Wisconsin* v. *Federal Power Commission*, 92 U.S. App. D.C. 284, 205 F. 2d 706.

and that the "Commission should fix the rates" for the Phillips

sales of natural gas for resale in interstate commerce. On June 7, 1954, the United States Supreme Court affirmed the opinion of the Court of Appeals.[3]

In compliance with the mandate of the Court of Appeals, the Commission, on November 22, 1954, issued its Order Vacating Termination of Proceedings and Continuing Investigation in Docket No. G-1148.

In each of the eight other dockets hereinabove designated,[4] the Commission has heretofore issued its order suspending proposed increases in rates and charges for sales of natural gas for resale in interstate commerce by Phillips. Such proposed increases approximate $2,300,000 per year in the aggregate. The sales and deliveries of gas involved in the eight designated suspension dockets are made by Phillips to Michigan-Wisconsin Pipe Line Company, Northern Natural Gas Company, Cities Service Gas Company, Arkansas-Louisiana Gas Company, El Paso Natural Gas Company, Consolidated Gas Utilities Corporation, Transcontinental Gas Pipe Corporation and Mississippi River Fuel Corporation. Such sales and deliveries of gas by Phillips involve questions of law and fact interrelated with those inherent in the matters involved and the issues presented in Docket No. G-1148.

The Commission finds:

It is appropriate and in the public interest in carrying out the provisions of the Natural Gas Act and good

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[3] *Phillips Petroleum Company* v. *Wisconsin, et al.*, 347 U.S. 672.

[4] Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883 and G-10359.

cause exists to consolidate the above-entitled proceedings for the purpose of hearing.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Power Commission by the Natural Gas Act, including particularly Sections 4, 5, 14, 15, and 16 thereof, and the Commission's General Rules and Regulations (18 CFR Chapter I), the proceedings in the above-designated Docket Nos. G-1148, G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883 and G-10359 be and the same hereby are consolidated for the purpose of hearing.

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(B) A hearing be held commencing on June 26, 1956, at 10:00 a.m.(EDST) in a Hearing Room of the Federal Power Commission, 441 G St., N. W., Washington, D. C., concerning the matters involved and the issues presented in the consolidated proceedings designated in paragraph (A) above.

(C) Interested State commissions may participate as provided by Sections 1.8 and 1.37 of the Commission's Rules of Practice and Procedure. [18 CFR 1.8 and 1.37 (f)].

By the Commission.

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30924

Docket Nos. G-1148 et al. and G-11217

Petition to Intervene by California Public Utilities Commission and People of California

Through the attorney for the Public Utilities Commission of the State of California, the people of the State of California and said Public Utilities Commission respectfully petition that they be authorized by appropriate order to intervene in these proceedings. This petition is filed pursuant to § 1.8 of the Commission's Rules of Practice and Procedure.

The attorney for the California Public Utilities Commission is empowered to "represent and appear for the people of the State of California" in proceedings of this character. Calif. Public Util. Code, Sec. 307.

I.

It is understood and believed and therefore alleged that Phillips Petroleum Company sells a significant amount of gas to El Paso Natural Gas Company, that in turn a significant amount of the gas which El Paso sells to public utility gas companies operating within California is derived from such gas furnished by

30925

Phillips, that in consequence the charges for gas by Phillips may affect the charges for gas by El Paso and in turn the charges for gas by public utility gas companies operating within California.

II.

The California Public Utilities Commission is empowered by constitution and statute to regulate the rates of public utility gas companies operating within California. Cal. Const., Art. XII, Secs. 22, 23; Calif. Public Util. Code

(Stats, 1951, ch. 764, as amended). Its interest in proceedings of this character is therefore derived from the responsibilities entrusted to it.

III.

In Docket No. G-11217, Phillips proposed originally an annual increase of $1,813,000 in rates for sales of gas to El Paso. At the most recent hearings in the consolidated proceedings herein, it was revealed that Phillips now proposes an increase of some $18,000,000 per annum in charges to El Paso. The magnitude of this new proposal and its serious potential impact upon utilities and consumers in California impels the California Public Utilities Commission to request authority to intervene herein. Being entrusted with the fixing of reasonable rates for gas service throughout California, the California Commission is the only entity which can adequately represent the public interest of all the California consumers which might be affected by Phillips' proposal.

IV.

An additional ground for seeking intervention herein is that the pleading recently filed by El Paso answering Phillips' motion to place into effect proposed rate changes and moving for dismissal of Docket No. G-11217, raises serious and important questions respecting "spiral escalation clauses" and the applicability of *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332.

V.

It is respectfully urged 1) that the right and interest of the California Public Utilities Commission in these proceedings is clear, 2) that no other entity is adequately

able to represent the public interest herein as it affects California customers and California utilities, 3) and that intervention at this juncture is necessary and appropriate in the light of Phillips' recent proposal and the issues raised by El Paso's recent pleading aforementioned.

WHEREFORE, it is respectfully petitioned that intervention be authorized.

Respectfully submitted,

THE PEOPLE OF THE STATE OF CALIFORNIA AND THE PUBLIC UTILITIES COMMISSION OF SAID STATE

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San Francisco, California

30999

Docket Nos. G-1148, G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10,359, G-10,793, G-10,883, G-11,125 and G-11,217

Order Denying Request for Limited Hearing and Permitting Increased Rates to Go Into Effect Subject to Refund

(Issued April 26, 1957)

On September 10, 1956, Phillips Petroleum Company (Phillips) tendered for filing proposed increases in rates for sales of natural gas to El Paso Natural Gas Company (El Paso) as follows:

Description	Purchaser	Rate Schedule Designation	Effective Date
Notice of change	El Paso Natural Gas Company	Supplement No. 19 to Phillips' FPC Gas Rate Schedule No. 32	October 11, 1956
Notice of change	El Paso Natural Gas Company	Supplement No. 6 to Phillips' FPC Gas Rate Schedule No. 234	October 11, 1956
Notice of change	El Paso Natural Gas Company	Supplement No. 8 to Phillips' FPC Gas Rate Schedule No. 64	October 11, 1956
Notice of change	El Paso Natural Gas Company	Supplement No. 5 to Phillips' FPC Gas Rate Schedule No. 7	October 11, 1956
Notice of change	El Paso Natural Gas Company	Supplement No. 11 to Phillips' FPC Gas Rate Schedule No. 9	October 11, 1956
Notice of change	El Paso Natural Gas Company	Supplement No. 8 to Phillips' FPC Gas Rate Schedule No. 33	October 11, 1956

(31000)

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Pursuant to an order issued on October 10, 1956, the Commission directed that a hearing be held concerning the lawfulness of the rates, charges, classifications, and services contained in Phillips' above-designated rate filings and suspended the filings for the statutory five-month period until March 11, 1957. The proceeding instituted for the purpose of determining the lawfulness of the increased rates and charges embodied in the above-designated rate filings has not been concluded, nor has a decision been rendered therein.

On October 17, 1956, Phillips filed an application for rehearing of the Commission's suspension order. This application was denied by order issued November 9, 1956. Thereafter, on November 26, 1956, Phillips filed a motion for consolidation of the proceeding in docket No. G-11,217 with the proceedings in docket Nos. G-1148, et al., which consolidation was subsequently made. On January 3, 1957, Phillips filed a petition and motion for shortening the suspension period from March 11 to January 3, 1957, and making the suspended rates effective on the latter date. Finally, on March 8, 1957, Phillips filed a motion to place the suspended rates in effect on March 11, 1957, at the end of the five-month suspension period. This motion is now pending action by the Commission.

Section 4(e) of the Natural Gas Act provides that whenever a new rate schedule is filed, the Commission shall have authority to enter upon a hearing concerning the lawfulness of the same; and that pending such hearing and the decision thereon, the Commission may suspend the operation of the new rate schedule, "but not for a longer period than five months beyond the time when it would otherwise go into effect."

Said section further provides:

> "If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate, charge, classification, or service shall go into effect. Where increased rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission; to keep accurate accounts in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts were paid, and upon completion of the hearing and decision, to order such natural-gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified."

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El Paso's filings in docket No. G-11,217 are almost as numerous as those of Phillips and beginning with its petition to intervene filed on September 18, 1956, El Paso has consistently opposed Phillips' proposed rate increases. In its said petition El Paso contends, *inter alia*, that certain of the pricing provisions contained in the contracts between itself and Phillips are "contrary to public policy."

On January 16, 1957, El Paso filed an answer to Phillips' petition for shortening of the suspension period wherein, after reviewing the pricing provisions of its rate schedules with Phillips, El Paso states: ". . . it is the position of El Paso that the gas purchase contracts which it has with Phillips do not provide any contractual basis for Phillips to file for the rate increases which it alleges it is entitled to receive from El Paso."

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On March 12, 1957, El Paso filed a tripartite pleading designated "Answer of El Paso Natural Gas Company to Motion of Phillips Petroleum Company to place into effect proposed changes in Rate Schedules; Motion by El Paso Natural Gas Company to dismiss Docket No. G-11,217, and; Request by El Paso Natural Gas Company for an early limited hearing on the issues here presented." In this pleading El Paso reiterates its contention that Phillips' proposed rate increases are void and of no legal effect because they are based upon spiral escalation provisions which are contrary to public policy. Further, El Paso contends that the operation of the spiral escalation provisions of the subject rate schedules have been suspended and are inoperative because of specific condition precedent to the filing of such increases has not been fulfilled. El Paso alleges that in such circumstances Phillips' increased rate filings are illegal and unauthorized under the rate schedules and constitute prohibited unilateral rate filings within the holding of the Supreme Court of the United States in the *Mobile* case[1] and consequently should be rejected and the proceeding in docket No. G-11,217, should be terminated.

Phillips, in its replies filed on January 25, March 27, and April 1, 1957, to El Paso's above-described pleadings, contends in substance that the condition precedent to its filing for increased rates under its rate schedule with El Paso has been satisfied; that the said filings are in accordance with the pricing provisions of the rate schedules; and that the increased rates should be made effective, subject to refund of excess charges, as of March 11, 1957.

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The records of the Commission disclose that, in addition to its above-designated sales of gas to El Paso, Phillips

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[1] *United Gas Pipe Line Company* v. *Mobile Gas Service Corporation*, 350 U.S. 432.

also sells gas to Panhandle Eastern Pipe Line Company (Panhandle) and to Michigan-Wisconsin Pipe Line Company (Michigan-Wisconsin) under rate schedules on file with the Commission, which schedules contain spiral escalation provisions similar to those complained of by El Paso as being "contrary to public policy." Increased rates filed by Phillips pursuant to such spiral escalation provisions have been suspended by the Commission, pursuant to Section 4 (e) of the Natural Gas Act, in the proceeding in docket No. G-10,793, a sale to Michigan-Wisconsin, and in the proceeding in docket No. G-10,883, a sale to Panhandle. Since both these proceedings, as well as the proceeding in docket No. G-11,217, have heretofore been consolidated for the purpose of hearing, with the proceedings in docket Nos. G-1148, *et al.*,[2] it is deemed appropriate and in the public interest that the legality of Phillips' rate filings in these three dockets be considered in the consolidated proceedings.

On March 15, 1957, Phillips tendered for filing an additional proposed rate increase for sales of natural gas under Phillips' FPC Gas Rate Schedule No. 4 to Michigan-Wisconsin. This proposed increase is based upon certain spiral escalation provisions in Phillips' said rate schedule which provide, in substance, that Phillips shall receive a proportionate increase in its rate for sale of gas to Michigan-Wisconsin when the latter company places in effect an increase in its wholesale rate for gas. By order issued in docket No. G-12,292 on March 28, 1957, the Commission suspended Michigan-Wisconsin's proposed increase in its wholesale rates, which increase was proposed to become effective on April 15, 1957, until September 15, 1957. Thus, although Phillips' related rate increase filing was timely filed on March 15, 1957, it cannot now, under the

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[2] *In the Matters of Phillips Petroleum Company*, docket Nos. G-1148, G-3175, G-5333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10,359, G-10,793, G-10,883, G-11,125, and G-11217 order issued December 14, 1956.

spiral escalation provisions of Phillips' said rate schedule, be accorded consideration by the Commission as an increased rate filing with an effective date prior to September 15, 1957, the date upon which Michigan-Wisconsin's related increased rate filing in docket No. G-12,292 may be made effective subject to refund of any excess charges thereafter found unjustified. Since Phillips' said increased rate filing of March 15, 1957, is based upon the same spiral escalation provisions in Phillips' FPC Gas Rate Schedule No. 4 that underlie Phillips' increased rate filing in the proceeding in docket No. G-10,793, for sales of natural gas to Michigan-Wisconsin, the question as to whether such recurring rate increase filings under the same escalation provisions in a rate schedule are contrary to the public interest is also presented for consideration and determination.

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The Commission finds:

(1) It is appropriate and in the public interest that the hearing being held in the consolidated docket Nos. G-1148, *et al.*, include among other things, the issues involved in docket Nos. G-10,793, G-10,883, and G-11,217 whether (a) Phillips' increased rate filings in the proceedings in docket No. G-11,217 for sales of natural gas to El Paso constitute unilateral filings within the meaning of the *Mobile* case (*United Gas Pipe Line Company* v. *Mobile Gas Service Corporation*, 350 U.S. 432); and (b) the spiral escalation provisions contained in Phillips' FPC Gas Rate Schedules Nos. 7, 8, 32, 33, 64, and 243 applicable to sales of natural gas to El Paso and the similar escalation provisions in Phillips' FPC Gas Rate Schedules Nos. 4 and 5 applicable to sales of natural gas to Michigan-Wisconsin and to Panhandle, respectively, are so ambiguous in language and so inflationary in effect as to contravane the public interest and conflict with the regulatory powers of the Commission, or are otherwise unlawful.

(2) El Paso's request for a limited hearing upon the specific issues enumerated in paragraph (1), above, should be denied.

(3) It is appropriate in carrying out the provisions of the Natural Gas Act to prescribe terms and conditions with respect to refunds by Phillips as hereafter provided.

The Commission orders:

(A) El Paso's request for a hearing limited solely to the issues presented in docket No. G-11,217, as set forth in paragraph (1) herein, is hereby denied.

(B) Upon execution by Phillips of the agreement and undertaking described in paragraph (D) below and acceptance thereof, evidence by letter addressed to Phillips by the Secretary of the Commission, the rates, charges, and classifications set forth in the supplements to its rate schedules as enumerated above, shall be effective as of March 11, 1957, subject to further orders of the Commission in this proceeding.

(C) Phillips shall refund at such times and in such amounts to the persons entitled thereto, and in such manner as may be required by final order of the Commission, the portion of the increased rates found by the Commission in this proceeding not justified, together with interest thereon at the rate of 6 percent (per) annum from the date of payment to Phillips until refunded; shall bear all costs of any such refunding; shall keep accurate accounts in detail of all amounts received by reason

of the increased rates or charges effective as of March 11, 1957, for each billing period, specifying by whom and in whose behalf such amounts were paid; and shall report (original and four copies) in writing and under oath, to the Commission monthly, or quarterly if Phillips so elects

and so notifies the Commission within 30 days, for each billing period, and for each purchaser the billing determinants of natural gas sales to such purchasers and the revenues resulting therefrom, as computed under the rates in effect immediately prior to March 11, 1957, and under the rates allowed by this order to become effective, together with the differences in the revenues so computed.

(D) As a condition of this order, within 15 days from the date of issuance hereof, Phillips shall execute and file with the Secretary of this Commission its written agreement and undertaking to comply with the terms of paragraphs (C) and (D) hereof, signed by a responsible officer of the corporation evidence by proper authority from the Board of Directors, and accompanied by a certificate showing service of copies thereof upon all purchasers under the rate schedule involved, as follows:

Agreement and Undertaking of Phillips Petroleum Company to Comply with the Terms and Conditions of Paragraphs (C) and (D) of Federal Power Commission's Order Making Effective Proposed Rate Change

In conformity with the requirements of the order issued 1957, in dockets Nos. G-11,217, et al., Phillips Petroleum Company hereby agrees and undertakes to comply with the terms and conditions of paragraph (C) of said order and has caused this agreement and undertaking to be executed and sealed in its name by its officers, thereupon duly authorized in accordance with the terms of the resolution of its Board of Directors, a certified copy of which is appended hereto, this day of 1957.

PHILLIPS PETROLEUM COMPANY

By:

President

Attest:

Secretary

(E) If Phillips shall, in conformity with the terms and conditions of paragraph (C) of this order, make the refunds as may be required by order of the Commission, the undertaking shall be discharged, otherwise it shall remain in full force and effect.

By the Commission.

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Decision

In the Matters of

Docket No. G-1148

Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10359, G-10793, G-10883, G-11125, and G-11217

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[* The Examiner's Decision, which has not been printed herein in its entirety, appears in full at 24 FPC 590-818]

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Zwerdling, Presiding Examiner: This case is an outgrowth of the historic June 7, 1954 decision of the United States Supreme Court in *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, which held that the Federal Power Commission has jurisdiction "over the rates of all wholesales of natural gas in interstate commerce, whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company."[1]

The Commission on October 28, 1948 had instituted *In the Matter of Phillips Petroleum Co.*, Docket No. G-1148, an investigation under Sec. 5(a) of the Natural Gas Act to determine whether Phillips was a natural-gas company within the jurisdiction of the Commission, and, if so, whether its natural-gas rates were unjust or unreasonable. The hearing, held in 1951, was directed solely to the jurisdictional question, and culminated in a Commission decision issued August 16, 1951, holding that Phillips was not a "natural-gas company" within the meaning of the Natural Gas Act. Accordingly, by an order accompanying that opinion the Commission terminated the investigation proceeding. On appeal, the decision of the Commission was reversed by the Court of Appeals for the District of Columbia[2], and on June 7, 1954 the United States Supreme Court affirmed the opinion of the Court of Appeals.

In compliance with the mandate of the Court of Appeals, the Commission on November 22, 1954 issued an order in Docket No. G-1148, vacating its previous termination of the G-1148 proceedings, and reinstituting the Sec. 5(a) investigation of Phillips' jurisdictional rates and charges under that docket. By Order issued May 28, 1956, the Commission consolidated the reinstated proceedings in

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[1] 347 U.S. at 682.

[2] *State of Wisconsin* v. *Federal Power Commission*, 205 F. 2d 706 (C.A.D.C., 1953).

Docket No. G-1148 for hearing with certain Sec. 4(e) rate increase proceedings filed by Phillips in Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883 and G-10359, and directed that hearing in such consolidated proceeding should commence June 26, 1956. After the hearing commenced, and during the pendency thereof, the Commission issued additional orders on July 25, 1956, October 24, 1956 and December 14, 1956, adding subsequent Sec. 4(e) rate increase filings by Phillips in Docket Nos. G-10793, G-10883, G-11125, and G-11217 to the instant consolidated proceeding. The increased rates proposed by Phillips in such Sec. 4(e) rate filings have since become effective at various dates subject to undertaking to assure refunds of any excess charges, and Phillips is currently collecting such increased rates and charges under such undertakings.

The hearing in the instant consolidated proceeding commenced on June 26, 1956 and was closed on December 18, 1957. It totaled 82 hearing days, and the hearing record comprises 10,620 pages of transcript and 235 exhibits.[3]

The parties include Phillips, the Staff of the Commission, and some thirty-one interveners.

Four major, full-scale cost-of-service studies were presented—by Phillips, the Staff, the Eastern Seaboard In-

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[3] Because the Commission order of November 22, 1954, *supra*, treated the instant proceeding as a reopening and continuance of the original 1951 Phillips hearing in Docket No. G-1148, the pagination of the transcript and the numbering of the exhibits in the instant hearing were treated in the same way. Accordingly, the record of the instant hearing commences with Volume 42, page 6223, and the first exhibit is Exhibit No. 197. As a matter of fact, since the original 1951 Phillips hearing was devoted solely to the jurisdictional question, and since that question has been finally disposed of by the Supreme Court's *Phillips* decision of June 7, 1954, the record made in the original 1951 hearing is not of interest in connection with this decision.

terveners (Eastern)[4], and the State of Wisconsin and Public Service Commission of Wisconsin (Wisconsin). In addition, evidence on various selected aspects of the cost of service and other problems was presented by certain other interveners—i.e., Southern California Gas Company and Southern Counties Gas Company of California (Southern); Pacific Gas and Electric Company (Pacific); Consolidated Edison Company of New York, Inc. (Consolidated Edison); El Paso Natural Gas Company (El Paso); and Minneapolis Gas Company.

It is relevant to note here a motion made by Wisconsin during the latter stages of the hearing, which was rejected by the Examiner, followed by a Commission order affirming the Examiner's ruling on December 17, 1957. During the direct testimony of the Wisconsin cost-of-service witness, Van Scoyoc, at the October 15, 1957 session, he indicated at various points that the record, in his opinion, was deficient in that certain types of data which he characterized only in general terms was not included. At the conclusion of Van Scoyoc's

direct testimony, Wisconsin's counsel orally moved the Examiner to make an order or otherwise direct that the Staff make the necessary studies and present on the record voluminous additional data of the type required to fill such alleged gaps. At the time when this request was made by Wisconsin, the Phillips and Staff cases in this proceeding had already long since been presented on both direct and cross-examination, and the request followed the long recess which had been granted for the period from June 13 to October 7, 1957, to provide the interveners with an op-

[4] Four Eastern Seaboard distribution company interveners, Long Island Lighting Company, Philadelphia Electric Company, Public Service Electric and Gas Company, and The United Gas Improvement Company, cooperated in making a joint presentation throughout this proceeding.

portunity to prepare their own cases for presentation at the October session. It also appeared that during the lengthy cross-examination of the Phillips' witnesses prior to such recess, counsel for the various interveners and the Staff from time to time had submitted various requests to Phillips for additional data of all types, which they contended was essential for the preparation of their cases. In order to handle this problem on an orderly basis, the interveners finally presented Phillips with a coordinated written list incorporating all of such additional data requests, and prior to the October 1957 session such data had in fact been made available by Phillips (101:13,407). In spite of these facts, no request for any such additional data as that outlined by Van Scoyoc had been made by Wisconsin in any form until the oral motion was made at the close of Van Scoyoc's direct testimony on October 15, 1957.

Under these circumstances, the Examiner denied the Wisconsin motion. On November 4, 1957, Wisconsin filed with the Commission a document entitled "Motion of State of Wisconsin and Public Service Commission of Wisconsin for Order Directing Staff to Supply Additional Evidence for Record." In this written motion, which the Commission treated as an appeal from the Examiner's ruling, Wisconsin requested that the Commission Staff undertake a study to obtain and incorporate in the record evidence with respect to the following matters:

(1) basic data necessary for the determination of just and reasonable rates for appropriate areas;

(2) comprehensive data with respect to gas purchased by Phillips;

(3) comprehensive data with respect to royalty transactions and lease buying and selling transactions;

(4) additional data with respect to cycling operations;

(5) additional data with respect to the methods and procedures utilized by Phillips in allocating income taxes to departments;

(6) additional data with respect to gas balance;

(7) additional data with respect to gasoline plants; and

(8) additional data with respect to Phillips' adjustments to the test year for "known" changes.

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By order issued on December 17, 1957, the Commission found that:

> " . . . Movants' request at this stage of the proceedings for the acquisition and inclusion of the substantial amount and variety of additional evidence is neither timely nor warranted."

Accordingly, the Wisconsin appeal from the Examiner's ruling was denied.

On December 2, 1957, two weeks before the lengthy hearing closed, Staff counsel orally moved the Examiner to grant a recess of six months in order to permit the Staff to make a further investigation of Phillips' books and records, for the purpose of adding to the record at a later session comprehensive data with respect to the costs of Phillips' joint product wells, broken down on an area basis, and the necessary allocation of such joint product costs on an area basis. The Staff contended that in the event the Commission should ultimately conclude that Phillips' rates should be fixed on an area basis, rather than a system-wide basis, it would be important for the record to contain such data. Actually, in its initial presentation of its case-in-chief in the summer of 1956 the Staff had presented a cost of service broken down into certain selected areas, using

actual cost figures for the dry gas produced by Phillips in such areas. However, because the Staff in the course of this presentation adopted the technique of simply imputing or assigning to gas produced from the joint product wells the same unit costs which had been derived for the dry gas production on an area basis[5], the Staff did not present actual cost figures on an area basis for the gas produced from the joint product wells. The purpose of the Staff motion of December 2, 1957 for the six months delay was to obtain and present on the record the required evidence to fill this gap.

As already noted, this Staff motion was made for the first time in the closing days of the already lengthy hearing, at a time when the record had already been completed with respect to: (a) the Staff case on direct and cross-examination; (b) the Phillips case on direct and cross-examination; (c) the presentations by various groups of interveners, on direct and cross-examination. The only unfinished business remaining open at that time was the presentation of a brief rebuttal case by Phillips. The Examiner denied the Staff motion on the ground that: (a) there was no justification for the delay in making such a motion until the closing weeks of the hearing, since the problems raised in the Staff motion had been apparent and obvious throughout the preceding eighteen months of hearing; (b) even if the Staff request had been granted

and the additional evidence sought thereby had been added to the record in the form of additional Staff exhibits, prepared upon the basis of the principles and positions adopted by the Staff in its cost-of-service study in this proceeding, such an expanded record would still not neces-

[5] This technique, as adopted by the Staff, will be described in detail at a later point in this decision.

sarily include all of the data required for area rate fixing, in the event the Commission should ultimately fail to adopt all of the Staff cost-of-service positions or techniques; (c) if the Staff motion had been granted, procedural due process would have required that both Phillips and the various intervener groups be subsequently provided with an opportunity to submit further substantial evidence of their own, directed to such a new Staff presentation, thus indefinitely delaying the closing of the record in this important proceeding; (d) respect for the administrative process required that the hearing be concluded and that the point of decision be reached without such interminable delay.

By order issued December 17, 1957 the Commission affirmed the Examiner's ruling.

The hearing was concluded on December 18, 1957. Thereafter comprehensive and extremely helpful briefs were filed with the Examiner by Phillips, the Staff, Eastern, Wisconsin, Southern, Pacific, Consolidated Edison, El Paso, Michigan Wisconsin Pipe Line Company (Michigan Wisconsin), Northern Natural Gas Company and Permian Basin Pipeline Company, Panhandle Eastern Pipe Line Company (Panhandle), Minneapolis Gas Company, Brooklyn Union Gas Company, Texas Gas Transmission Corporation, and the County of Wayne, Michigan. The last reply briefs were filed as of May 5, 1958, and the case is now ready for decision.

As a result of the excellent and helpful presentations made by the various parties in this case, the instant record includes a comprehensive presentation with respect to all of the major, key problems, including four different complete cost-of-service studies, and including the presentation and testing by cross-examination and rebuttal of the major alternative allocation methods which have thus far been proposed in independent producer rate cases currently

pending before this Commission. It is further concluded that, in spite of the allegations made in the Wisconsin and Staff motions referred to above, the record made in the instant proceeding does provide an adequate and sufficient basis for a reasonable resolution of all the issues presented in this case.

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I. The Landmark Court and Commission Decisions in the Field of Producer Regulation, by Which this Case is Governed

In proceeding to our discussion of the important producer problems involved here, it will be helpful to restate and to bear in mind certain basic and controlling statements made by the Supreme Court in its historic *Phillips* decision, *supra*. The Court there referred to its earlier decision in *Interstate Natural Gas Company* v. *Federal Power Commission*, 331 U.S. 682, involving a company which produced or purchased natural gas, which it in turn sold and delivered to three interstate pipeline companies. The Court then quoted with approval the following language from its earlier *Interstate* decision:

> "'We have held that these sales are in interstate commerce. It cannot be doubted that their regulation is predominantly a matter of national, as contrasted to local concern. All the gas sold in these transactions is destined for consumption in States other than Louisiana. Unreasonable charges exacted at this stage of the interstate movement become perpetuated in large part in fixed items of costs which must be covered by rates charged subsequent purchasers of the gas, including the ultimate consumer. It was to avoid such situations that the Natural Gas Act was passed.' Id., at 692-693" (347 U.S. at 680).

At the conclusion of its decision in the *Phillips* case the Supreme Court stated:

> "Regulation of the sales in interstate commerce for resale made by a so-called independent natural-gas producer is not essentially different from regulation of such sales when made by an affiliate of an interstate pipeline company. In both cases, the rates charged may have a direct and substantial effect on the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural-gas companies was the primary aim of the Natural Gas Act. *Federal Power Commission* v. *Hope Natural Gas Co., supra*, at 610. Attempts to weaken this protection by amendatory legislation exempting independent natural-gas producers from federal regulation have repeatedly failed, and we refuse to achieve the same result by a strained interpretation of the existing statutory language."

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Since the Supreme Court's historic holding in the *Phillips* decision, *supra*, that the Commission has jurisdiction over independent producer natural gas sales in interstate commerce, there have been two major Court of Appeals decisions dealing with the broad problem as to how "just and reasonable" rates should be determined for such producer sales under the Natural Gas Act.

The basic, controlling decision in this area was handed down on December 15, 1955 by the Court of Appeals for the District of Columbia Circuit in the *City of Detroit* case, *City of Detroit* v. *Federal Power Commission*, 230 F. 2d, 810, *certiorari* denied, 352 U. S. 829. As will be noted below, the Commission since that time has regarded the *City of Detroit* decision as controlling in independent producer rate cases. Under the circumstances, it will be

helpful at this point to summarize the holding of the *City of Detroit* case at some length. That case was a proceeding to determine "just and reasonable" rates for the jurisdictional sale of natural gas by Panhandle Eastern Pipe Line Company, and the issue before the Court was whether the Commission had erred in fixing "just and reasonable" rates for Panhandle's own produced gas on the basis of "field price" or "commodity value." The Court held that the Commission had erred, and in the course of its decision setting aside the order of the Commission the Court laid down the following basic principles:

(1)

"... the primary aim of the Act in the words of the Supreme Court is 'to protect consumers against exploitation at the hands of natural gas companies'. *Federal Power Commission* v. *Hope Natural Gas Company*, 320 U. S. at 610. See also, Id. at 612; *Phillips Petroleum Company* v. *Wisconsin* 347 U. S. 672, 685." (230 F. 2d at 815).

The Court further stated that in considering whether investor and consumer interests were properly balanced,

"... we must keep in mind the basic purpose of the statute to protect consumers from excessive ..tes, though at the same time the statute affords the support of public authority to the regulated utility." (230 F. 2d at 816).

(2) The Court noted that:

"In *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U. S. 591, the Supreme Court approved use of the 'prudent investment' rate-base method for establishing rates to be charged by natural gas

companies. Since then, until the instant case, the Commission has consistently employed this rate-base method, under which rates are considered 'just and reasonable' if they will return to the company a certain percentage of profit on its rate base. The rate base is a figure representing the money prudently invested in the properties and equipment utilized in the company's transmission and production business. The percentage of profit prescribed by the Commission depends upon a variety of factors, such as the risks of the business, the necessity for attracting capital, and the desirability of lower cost of gas to the public. In order to return a profit on the rate base the rates are set high enough to recover all costs of service, including taxes, depreciation, depletion, and all operating expenses chargeable to production and transmission." (230 F. 2d at 813).

(3) Although holding that the use of field price was not necessarily prohibited,[6] the Court noted:

"The fair field price . . . is not an item of cost. Its inclusion as an amount to be recouped from consumers as though it were a cost incurred by Panhandle must find some other justification within the periphery of the 'just and reasonable' standards. It is not an ingredient of any of the usual needs of a regulated utility, that is, to obtain revenues for operating expenses, for preservation of its financial integrity, for capital costs, for servicing of debt and payment of dividends, or for delayed rentals or costs of exploration and development. See *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U. S. at 605, 615. The Commission, how-

[6] 230 F. 2d at 814, 815.

ever, advances other factors of an economic character as justification. We may not deny these a place in the total structure underlying rates if, in a balancing of investor and consumer interests, they are brought by evidence and findings into rational relationship to what is 'just and reasonable'." (230 F. 2d at 816).

(4) The Court then held that use of the field price method can be justified "only in terms of a demonstrated public interest"; that when so used

". . . the evidence and findings must show that the increase in rates thus caused is no more than is reasonably necessary for the purposes advanced for any increase." (230 F. 2d 818).

(5) The Court finally held:

"While as we have indicated the Commission may be empowered to consider some of these factors it must also, and always, relate its action to the primary aim of the Act to guard the consumer against excessive rates. If the Commission contemplates increasing rates for the purpose of encouraging exploration and development, or the ownership by pipeline companies of their own producing facilities, it must see to it that the increase is in fact needed, and is no more than is needed, for the purpose. Further than this we think the Commission cannot go without additional authority from Congress." (230 F. 2d 817).

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"Furthermore, it is seen that when we refer to an 'increase' we mean an increase in the rates above those which would result from use of the conventional rate-base method. For, though we hold that method not to

be the only one available under the statute, it is essential in such a case as this that it be used as a basis of comparison. It has been repeatedly used by the Commission, and repeatedly approved by the courts, as a means of arriving at lawful—'just and reasonable'—rates under the Act. Unless it is continued to be used at least as a point of departure, the whole experience under the Act is discarded and no anchor, as it were, is available by which to hold the terms 'just and reasonable' to some recognizable meaning." (230 F. 2d 818-19).

Subsequently in Opinion No. 300, *In the Matters of Union Oil Company of California, et al.*, Docket Nos. G-4331, *et al.* (December 6, 1956), the Commission held that the *City of Detroit* decision was

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controlling in independent producer rate cases. Later, in its "Order Denying Petitions for Rehearing and Amending Order Accompanying Opinion No. 300" (issued January 31, 1957), the Commission held that the *City of Detroit* decision required:

". . . the presentation of rate base and cost evidence as a point of departure plus a showing that any additional allowance is no more than is reasonably necessary for the purposes advanced for any increase. . . .
"Significantly, in the *City of Detroit* case, the court was interpreting the substantive statutory and constitutional standards which we must follow. These are applicable to the rates of all natural-gas companies whether they be interstate transmission companies or independent producers. We carefully considered the applicants' contentions with respect to the *City of Detroit* case before we issued our Opinion No. 300 and could find no legal basis for excluding independent

producers from the application of the law of that case. Further, this conclusion is consistent with the effect of the decision in *Phillips Petroleum Company* v. *Wisconsin*, 347 U. S. 672 (1954)." (p. 4 of Mimeo. Order)

On review of Opinion No. 300, this holding was affirmed by the Court of Appeals of the Fifth Circuit in *Bel Oil Corporation* v. *Federal Power Commission*, 255 F. 2d 548 (April 23, 1958).[7] In the course of its decision upholding the Commission in that case, the Court quoted at length, as being germane to the Commission decision it was there affirming, the following language from the *City of Detroit* decision:

"For, though we hold that method [the rate base or cost of service method] not to be the only one available under the statute, it is essential in such a case as this, that it be used as a basis of comparison. It has been repeatedly used by the Commission, and repeatedly approved by the courts, as a

means of arriving at lawful—'just and reasonable' rates under the Act. Unless it is continued to be used at least as a point of departure, the whole experience under the Act is discarded and no anchor, as it were, is available by which to hold the terms 'just and reasonable' to some recognizable meaning." (255 F. 2d at 551-552)

The Court further held, in the *Bel Oil decision*:

"We do not hold that evidence of field price is irrelevant. We do hold that evidence of unregulated prices in the field is not sufficient to warrant a finding by the

[7] Certiorari denied October 13, 1958.

> Commission that a price comparable to them is just and reasonable within the intendment of the Natural Gas Act. Neither is evidence of the field price when coupled with the opinion of experts that the price must be high enough to provide an incentive for exploration and development of new sources of supply." (255 F. 2d at 553)

Since the *City of Detroit* decision, *supra*, the Commission has consistently held in numerous independent producer rate cases that the conventional rate base method of rate-making must be used as a basis of comparison or point of departure.[8] The Commission has most recently reaffirmed that position in strong language in its Order Denying Applications for Rehearing and Motions for Stay, *In the Matters of Pan American Petroleum Corporation, et al.*, Docket Nos. G-8697, *et al.*, (issued June 6, 1958), where it stated:

> ". . . the companies cannot show their proposed increased rates are just and reasonable, absent evidence of cost-of-service or revenues requirements . . .[9]

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The Court of Appeals for the Fifth Circuit has recently had occasion to comment upon this situation again in a decision issued on February 20, 1959, in *Forest Oil Corporation, et al.*, v. *Federal Power Commission* (CCA 5, No. 16844). The *Forest Oil* case was identical in character with the *Bel Oil* case, *supra*, and presented the same questions

[8] *Sun Oil Co., et al.*, Docket Nos. G-8288, *et al.*, Feb. 6, 1957; *Orange Grove Oil and Gas Corporation, et al.*, Docket Nos. G-8518, *et al.*, Feb. 6, 1957; *Crow Drilling Company, Inc., et al.*, Docket Nos. G-6622, *et al.*, Feb. 6, 1957; *H. F. Sears, et al.*, Docket Nos. G-6502, *et al.*, Sept. 3, 1957; *Delhi-Taylor Oil Corp., et al.*, Docket No. G-6504, Sept. 30, 1957.

[9] Page 4, Mimeo. Order.

for review—i.e., (1) whether field price evidence alone was sufficient to make a *prima facie* case that the producer's proposed rates were just and reasonable, and (2) whether, in the event such evidence was not regarded as sufficient, the record should be reopened to give the petitioners one more opportunity to present satisfactory evidence in support of their rate proposals. The Court adopted the same position which it had taken in the *Bel Oil* case, *supra*, affirming the Commission's finding that field price evidence alone was not sufficient, but directing that the proceedings be reopened to afford petitioner

> "reasonable opportunity to adduce such evidence as it may be advised is relevant to the inquiry whether the proposed rate is just and reasonable".

Although there was nothing further before the Court for disposition, it noted the persistent and strong pleas which had been made by petitioner's counsel in the course of oral argument for some further guidance as to the types of evidence which might be deemed relevant on the issue of just and reasonable rates. Because of these pleas, the Court in the *Forest Oil* decision proceeded to set forth several pages of general observations, by way of *dictum*.

That Court without a doubt has been amply supplied, both in the *Bel Oil* series of cases and in the *Forest Oil* case, with all of the general arguments which all segments of the natural gas industry, the Staff of the Federal Power Commission, and State regulatory commissions have now been making since June 7, 1954 on the general theoretical question whether producer rates can or should be fixed under the rate base or cost of service method, whether that method is administratively feasible or impossible of administration, whether it produces sensible or ludicrous results, *etc.* It is of utmost importance, however, to note that all of the arguments made on these subjects up to this

time have been made *in a vacuum*. The fact of the matter is that up to this date neither the Federal Power Commission itself, nor the Court of Appeals for the Fifth Circuit, nor any other Court, has yet had the opportunity to examine a record made in a major, representative producer rate case, in which the rate base or cost of service method has actually been applied to the books and records of a specific producer, and in which an actual attempt was made to develop "just and reasonable" rates for the producer by that approach.

That very opportunity, however, is now provided, for the first time, in the instant *Phillips* proceeding. In view of the circumstances outlined above, it is here concluded that the general observations set forth by the

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Court in the *Forest Oil* decision by way of *dictum* were intended by the Court to be treated only as preliminary and advisory in character, and not as a firm and binding precedent which would be dispositive of any of the issues involved in the instant *Phillips* proceeding.

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II. General Attacks on the Cost-of-Service Method

However, in spite of the fact that the Courts and the Commission have thus consistently held that in determining "just and reasonable" rates for jurisdictional natural gas sales by independent producers the conventional rate-base, or cost-of-service method must be used at least as a point of departure, arguments continue to be made in producer rate cases before this Commission that producer rates should not be fixed under the cost-of-service or rate-base method. In the instant proceeding thirteen pages of the El Paso brief are devoted to arguing that "independent producer rates cannot be determined by the traditional rate base cost of service method applicable to transportation

utilities" (El Paso brief, pages 20-33). Contentions are made that the cost-of-service method, as applied to producer rate cases, is unworkable, that it presents monstrous problems which are impossible of solution, that it is administratively unfeasible, and that it produces incongruous results.

Since this is the first major, comprehensive cost-of-service producer rate case to reach the point of decision before this Commission, it is anticipated that it will provide a vehicle for resolving many of the major problems connected with producer rate regulation which have remained unsolved up to this time. Furthermore, in view of the comprehensive and helpful cost-of-service presentations made in this proceeding by Phillips, a number of representative groups of interveners, and the Staff, an opportunity has been provided to observe concretely, on the basis of fact, rather than on the basis of academic, general speculation, the problems encountered in attempting to fix producer rates on a cost-of-service basis, the methods which are available to resolve those problems, and the nature and reasonableness of the results obtained. Accordingly, it would seem useful to set forth here certain relevant over-all conclusions, based upon what was developed in this proceeding.

It may be noted at the outset that Phillips itself has taken the position throughout this proceeding that its "just and reasonable" rates should be determined under the cost-of-service method, rather than under a field price method. (92: 12,481, lines 10-15)[10]

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The Phillips position was clearly stated by its policy

[10] Based on its claimed cost-of-service as proposed by Phillips in this proceeding, it has developed proposed rates ranging from a high of 22.75¢ per Mcf to a low of 16.5¢ per Mcf, depending on delivery conditions. (Phillips initial brief, page 169) Such maximum proposed rate of 22.75¢ is higher than any of the claimed "commodity value" or "field price" levels presented in this proceeding.

witness, Stanley Learned, Chairman of the Executive Committee and Assistant to the President of Phillips, during cross-examination by El Paso counsel. In the course of this interrogation El Paso counsel referred to the question as to how the concept of commodity value (or field price) could be employed in regulation. The following colloquy then occurred:

"Q. And do I understand that you think that that should be the method by which the prices of independent producers should be regulated, rather than by the cost of service method?

A. No, I do not think so.

Q. Did you formerly espouse that method for regulation?

A. The value method?

Q. Yes.

A. No, sir.

Q. *Now, is it your position, sir, that when these parties at arms-length deal and effect a price which represents the value, as you have defined it, that that is the fair and equitable price?*

A. Under regulation?

Q. Either way, sir.

A. *It is not necessarily fair and equitable under regulation.*

Q. You think then, that despite the fact that the parties agree at arms-length with these elements that you have in mind, that nevertheless that should be abandoned and a cost of service method rather instituted to determine the price?

A. *Well, under regulation I think that the interests of the consumer and the interests of the public have to be given consideration, and they may not have been given consideration at the time that the contract was*

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entered into." (93: 12,494, line 23—12,495, line 22; emphasis supplied.)

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It is also relevant to note that, on the basis of its own *actual* experience in presenting its instant case on a cost-of-service basis, Phillips has not at any time taken the position that the cost-of-service method, as applied to producer rate cases, is unworkable, or that it presents unduly complex problems. On the contrary, the Phillips initial brief summarizes the situation as follows:

"Important differences exist among the parties in the various methods of allocating costs. Before discussing differences, however, it is important to note the similarities. The differences in basic approach are not as great as they might appear. While there was disagreement among the parties with respect to specific matters, there was complete unanimity with respect to many of the fundamental principles which serve as the starting point for any method of cost allocation." (page 83)

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"In addition to these points of agreement on basic principles, it becomes clear upon analysis that many of the apparent differences are merely differences in the application of the same method, rather than differences in choice of methods. The result is that, while the various cost studies by no means represent complete harmony, there is surprising unity of thought to a novel problem which is by its nature complex and filled with potential points of controversy." (page 85)

We now turn to some of the major contentions made by those who oppose the use of the cost-of-service method for the regulation of producer rates:

(1) It is pointed out that over four years have now elapsed since the Supreme Court's historic *Phillips* de-

cision and that no final solutions have yet been arrived at for the major problems involved in applying a cost-of-service method to the determination of "just and reasonable" producer rates—and this fact is advanced as evidence that the complexity of the problems is such as to render the cost-of-service method unworkable in this field. However, a somewhat different impression will be obtained if the history of the past four years is briefly examined. The fact of the matter is that the first two years subsequent to the Supreme Court's *Phillips* decision on June 7, 1954, constituted a phase during which the producers abstained from presenting any evidence with regard to cost-of-service or revenue requirements. During this period the evidence presented by producers in producer rate hearings before the Commission consisted only of such matters as field price evidence, together with testimony and exhibits designed to persuade the Commission that the public interest would be better served if producer prices were left to be fixed by the law of supply and demand rather than by regulation. This phase culminated in the Commission decision issued December 6, 1956, in the

Union Oil case (Op. No. 300, *supra*), subsequently affirmed by the U. S. Court of Appeals for the 5th Circuit on April 28, 1958,[11]—in which it was held that evidence of field prices and evidence of arm's-length bargaining alone were not sufficient to sustain the burden of proof as to "just and reasonable" rates, imposed upon the producers under Sec. 4(e) of the Natural Gas Act. Thereafter the second phase commenced in June 1956 with the instant *Phillips* proceeding in which, as noted above, a comprehensive cost-of-service presentation has been made by Phillips and the other parties. In addition, a number of other major pro-

[11] *Bel Oil Corporation* v. *Federal Power Commission*, 255 F. 2d 548.

ducer rate cases have been in hearing before this Commission, in which comprehensive cost-of-service studies have been presented. It would seem reasonable to expect that this second phase, which commenced only two years ago, will produce the experience and the understanding required to develop reasonable, fair and workable solutions for the major problems.

(2) Those who oppose the use of the cost-of-service method also stress the size of the record and the length of the hearing in the instant *Phillips* proceeding as evidence of the allegedly impossible complexity of the task. However, it is important to note in this connection that the instant proceeding represents the first major producer rate case before this Commission to reach the point of decision; that the Commission at this point is still at the threshold of the problem of producer rate regulation, and that no firm positions have yet been reached by the Commission on any of the major issues involved in this area. Under these circumstances, it was inevitable that a very substantial portion of the record made in this proceeding should necessarily fall into the following major categories:

(a) The presentation by Phillips, numerous intervener groups and the Staff of a large number of different, alternative proposals for the handling of various allocation problems, and for the solution of other issues such as the type of rate of return to be developed for producers, the treatment of "phantom" taxes, etc. Each one of these numerous alternative proposals was, of course, followed by detailed cross-examination and rebuttal.

(b) The presentation by Phillips of voluminous general, industry-wide data and material, designed to indicate certain allegedly basic characteristics and trends operating with respect to the natural gas

production industry—i.e., the national gas supply picture, increasing market requirements, and increasing cost trends. This type of evidence was designed to suggest that where various alternative methods are available, a method liberal to the producer should be adopted.

It is important to bear in mind, however, that the length and complexity of the instant *Phillips* proceeding cannot fairly be regarded as representative of the situation which will be commonly encountered in future producer rate proceedings, once the Commission has firmly established the applicable standards and methods to be used in determining producer rates. From that point on, the two categories of evidence outlined above, which consumed so much time in the instant *Phillips* proceeding, will no longer be required.

(3) A further argument is made with respect to the claimed difficulty of obtaining from the producer's records the type of data required to develop a true cost of service and to make the necessary allocations. It is contended that in many cases such data is not available in the required form because producers normally do not keep their books in this manner; that it accordingly imposes a serious burden upon the producers to develop such data from the information on their books. It is interesting to note, however, that before the record was closed in the instant proceeding all reasonable requests made to Phillips by the interveners and Staff for additional data had been met. No contention can seriously be made here that the instant record does not contain all the data with respect to Phillips' operations which is reasonably required for the resolution of the major problems in this case.

It is also relevant to note that difficulties similar to those referred to above were ultimately solved in the early years of this Commission's regulation of pipeline rates by the adoption of such techniques as a Uniform System of Accounts, under which pipeline companies subject to Commission regulation were required to set up and maintain their records in such a way that the required data would at all times be readily available. There is no reason to doubt that the Commission will be able to work out similarly effective techniques for solving such problems in connection with the exercise of its jurisdiction over independent producers.

(4) One of the major arguments made against the use of the cost-of-service method for regulation of producer rates is directed to the complexity of the allocation problems arising in connection with joint product wells. As in the case of most producers, Phillips produces gas not only from dry gas wells, but also from joint product wells. The latter category includes casinghead gas wells, producing both oil and casinghead gas, and gas condensate wells which produce condensate gas and condensate liquids.[12] Since the pro-

duction costs of such joint product wells are joint costs, it becomes necessary to allocate such joint costs as between oil and gas. In addition, joint exploration costs must be allocated as between the two products. A major portion of the record in this proceeding was directed to the presentation of alternative methods for making such allocations. Opponents of the cost method argue that such allocations are tremendously complicated and difficult; that because there is in fact no such thing as a *separate* cost for the gas

[12] The gas produced from joint product wells is also referred to as "associated gas".

produced from a joint product well, the results arrived at by the use of any of such allocation methods do not represent the costs *actually* incurred with respect to the separate product, and, accordingly, the entire effort to determine which allocation method should be adopted is misdirected.

It can be agreed, at the outset, that there is in fact no such thing as a separate cost for the gas produced from a joint product well, and that allocations must, therefore, be made. However, this fact becomes less impressive when it is realized that pipeline rate proceedings, where the cost-of-service method has for years constituted the established and accepted approach, similarly involve complicated and difficult allocation problems. It will help to restore this situation to perspective if a brief reference is made here to some of the complex allocation problems commonly encountered in pipeline rate proceedings.

(a) One such pipeline allocation problem, which is present in practically all pipeline rate proceedings, is the determination as to what portion of system-wide costs should be classified as demand costs, and what portion as commodity costs. This allocation becomes necessary because pipelines perform both a capacity and a volumetric function, and therefore represent, in a sense, a joint facility.

The leading Commission decision on this particular problem was *In the Matter of Atlantic Seaboard Corporation, et al.*, 11 F.P.C. 43 (April 25, 1952). The language there used by the Commission on the subject of cost allocation can be read with interest and profit here:

> "In this, as in most of our natural gas rate proceedings, we are confronted with a cost allocation problem.
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> • • • • • • • • • •
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> "Because this question of proper allocation of costs is of such great importance in practically all rate proceedings before us—and usually, as here, is one of the most controversial of issues—we consider it appro-

priate to set out at some length our views as to proper methods of cost allocation so that all may be informed and guided in situations which may be substantially similar to the conditions here present.

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"The controversy generally engendered in rate proceedings as to the proper method for allocation of costs stems largely from the fact that the relative importance of the demand (capacity) and commodity (volume) functions cannot be measured with scientific accuracy. In the final analysis the allocations of cost to these respective functions are and must be largely dictated by informed judgment. Throughout our administration of the Natural Gas Act we have continually strived to develop—and improve—methods of allocation which would most properly apply to the natural-gas industry activities subject to our jurisdiction in the matter of rates. The methods used in the determination of early rate proceedings were modified somewhat in our latter decision in the Mississippi River Fuel Corp. case because additional experience under the methods first applied indicated the necessity for modification thereof. Further experience and knowledge gained since the time of our decision in the Mississippi River Fuel Corp. case—continuing study of this troublesome question—and the facts in evidence in this proceeding disclose the need for further departure from methods of allocation previously applied if results are to be obtained which are equitable to the various classes of customers and which attribute to each such class their proper share of the cost.

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"A natural-gas transmission facility performs both a capacity and a volumetric function. In this sense it is

a joint facility, which thus presents the problem, always difficult, of allocating joint costs. This problem is not unlike that which was presented to the Supreme Court in the Colorado Interstate case,[21] as to which it was stated: 'Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science. Hamilton, Cost as a Standard for Price, 4 Law & Contemporary Problems 321.' "

"[21] *Colorado Interstate Gas Co.* v. *Federal Power Commission*, 324 U. S. 581, 589." (11 F.P.C. pp. 52-54)

Although the pipeline cost allocation problem above described was thus recognized as an extremely difficult one, commonly involving one of the most controversial of issues, inherently incapable of being resolved with scientific accuracy, and therefore calling for the application of "informed judgment," it was not there contended and it has, in fact, never been contended that the presence of such complex allocation problems in pipeline rate proceedings requires or warrants the abandonment of the cost-of-service method in such cases.

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(b) Another complex allocation problem arises in pipeline rate proceedings where rates for a given pipeline system are fixed on a zone basis, rather than on a system-wide basis. In such cases it becomes necessary to determine what portion of the pipeline company's total system-wide costs should fairly be borne by each of the different zones, and this requires the application of complicated allocation methods. An illustrative case of this nature was Op. No. 281 (May 20, 1955), *In the Matter of Northern Natural Gas Co.*, Docket No. G-2217. The Commission there noted that

the allocation problem before it was not susceptible to solution with scientific accuracy. It stated:

> "In theory, the ideal, non-discriminatory, and non-preferential rate structure would be one designed to assess each point of sale and delivery with the total of the various cost components incurred in the rendering of service to each point. *But any attempt to arrive at such perfection would be . . . delusory.*[16]

[16] *Colorado Interstate Gas Company* v. *Federal Power Commission, et al.*, 324 U. S. 581, 589; Hamilton, Cost as a Standard of Price, *supra;* Op. No. 225, *In the Matter of Atlantic Seaboard Corporation, et al.*, pp. 17-19 (mimeo ed.)" (Op. No. 281, pages 21-22; emphasis supplied)

Nevertheless, in spite of the great complexity of the problem and the impossibility of obtaining perfection, the Commission there proceeded to make a detailed and careful analysis of the problem, and applied its judgment and expertise to arrive at a solution. That solution was upheld by the Court of Appeals for the 8th Circuit in *Interstate Power Company* v. *Federal Power Commission*, 236 F. 2d 372, (July 9, 1956)[18], in an opinion which referred to the Commission as:

> "'one of the agencies presumably equipped or informed by experience to deal with a specialized field of knowledge, whose findings within that field carry the authority of an expertness which courts do not possess.' *Universal Camera Corp.* v. *National Labor Relations Board*, 340 U.S. 474, 488. . . . Its 'function is not only to appraise the facts and to draw inferences from them, but also to bring upon the problem an expert judgment.' *United States* v. *Detroit & Cleveland Navigation Co.*, 326 U.S. 236, 241." (236 F. 2d at 385)

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(5) The Courts have never regarded the cost-of-service

[18] Certiorari denied 352 U.S. 967, January 14, 1957.

method for regulation of pipeline rates as being unworkable or unsatisfactory because complex allocations were required, or because such allocations were not susceptible to mathematical exactness. In *Colorado Interstate Gas Co. v. Federal Power Commission*, 324 U.S. 581 (1945), the U. S. Supreme Court stated:

> "Allocation of costs is not a matter for the slide rule. It involves judgment on a myriad of facts. It has no claim to an exact science. Hamilton, Cost as a Standard for Price, 4 Law and Cont. Prob. 321. But neither does the separation of properties which are not in fact separable because they function as an integrated whole." (324 U.S. at 589). . . .
>
> "These circumstances illustrate that considerations of fairness, not mere mathematics, govern the allocation of costs." (324 U. S. at 591)

In a later case, *Colorado Interstate Gas Co. v. Federal Power Commission*, 209 F. 2d 717 (CCA 10, 1953), one of the major issues before the Court was the question as to how joint costs of producing and gathering the wet gas stream to the inlet of the gasoline plants should be allocated as between residue gas and gasoline. The Commission had adopted the relative value method, as presented by the Staff, whereas the pipeline company argued for the adoption of a volumetric method. In affirming the Commission, the Court stated:

> ". . . True, it did say that neither method was entirely satisfactory, but the same could be said with respect to any method which might be proposed. Mathematical exactness in the apportionment of cost is an impossibility. Because a method may have some infirmities does not of itself condemn it as a proper method.[8] It

[8] *Colorado Interstate Gas Company v. Federal Power Commission*, 324 U.S. 581, 65 S. Ct. 829, 89 L. Ed. 1206. (209 F. 2d at 726)

is the duty of the Commission to select that method which in its considered judgment more nearly reaches a just and sound result. The Commission did approve and apply the relative value method, and without extended discussion, we think its conclusion, with respect thereto finds support in the record and is, therefore, approved.

Similarly, with respect to the joint cost allocation problems presented in the instant *Phillips* proceeding, where we are attempting to determine what portion of the joint product well costs should fairly be borne by gas and what portion should fairly be borne by oil, a

number of different alternative methods have been suggested—as to each of which it may fairly be said that there are some advantages and some disadvantages. Our problem is to determine, as among all of those possible alternative methods, which one more closely meets the following basic requirements:

(a) that it assigns a fair share of the joint costs to gas;

(b) that it is a method which can be practicably administered, and that the data required is not unreasonably difficult to obtain and the method itself is not unreasonably cumbersome and time-consuming;

(c) that the results reached, through applying such method, make sense.

In spite of what has been said above, it would not be realistic or fair to suggest here that there are not extremely difficult problems to be solved in working out the application of a cost-of-service approach to producer rate-fixing. However, the resolution of those problems requires the following steps:

(a) reasonably prompt determination by the Commission as to the various criteria, standards and methods to be applied in this area;

(b) the subsequent consideration of techniques which would result in producer records being kept in such a manner that the data required for the application of such determined methods and criteria would thereafter be readily available;

(c) the gradual and continuous accumulation of experience in applying such determined methods and criteria from case to case, this being the normal process by which all regulatory agencies develop the implementation of established general methods and criteria, until finally the problems no longer appear to be unmanageable.

III. Summary of Phillips Operations

Before turning to a discussion of the specific cost-of-service issues involved in this proceeding, it would be appropriate to summarize briefly the nature of Phillips' operations. Phillips was incorporated on June 13, 1917. Its principal executive offices are located at Bartlesville, Oklahoma, and New York City. The company is a diversified, integrated enterprise engaging in virtually every phase

of petroleum industry operations and many related petrochemical activities in the United States (Exh. 296, p. 7). These activities include the exploration for and the development and production of oil and gas, the purchase of oil and gas from other producers, the gathering of natural gas, the processing of natural gas in gasoline plants for the extraction of liquid hydrocarbons, the refining of crude oil and

other petroleum products, the manufacture and sale of various chemicals, the operation of crude oil and refined products pipelines, the sale of refined petroleum products through various types of marketing outlets, and the research for and development of new products (56:7856). Its over-all operations are spread throughout the United States.[14]

In terms of total consolidated balance sheet assets as of December 31, 1955, Phillips was ninth in size among oil companies in the United States (Exh. 296, p. 7). It is one of the largest gas producers in the United States (p. 112 of Phillips' initial brief). However, its annual revenue from sales of natural gas in 1955 were slightly less than 6% of the company's total gross income from all sources (Exh. 222, p. 26). In the test year 1954, Phillips sold 688,811,312 Mcf of natural gas, of which 491,178,953 Mcf, or 71.3 percent of the total, were sales for resale in interstate commerce. A total of 375,690,912 Mcf of gas was produced in that year, and an additional 407,984,210 Mcf was purchased from other producers (Exh. 224).[15]

Phillips' natural gas operations extend from the Gulf Coast to Montana and Wyoming, with its greatest concentration of sales occurring in Texas, Louisiana and Oklahoma. In addition to its natural gas operations, it owns all or part interest in 43 gasoline plants, 27 of which are wholly owned (56:7865).

Of the more than twenty different departments which carry on Phillips' operations, three are directly concerned with the production, handling and sale of natural gas. These are the Natural Gas Department, the Natural Gaso-

[14] Phillips also has operations in several foreign countries, but these operations are, of course, not involved in the instant proceeding.

[15] The difference between the total volume sold, and the somewhat higher total volume produced and purchased, consists of company uses, losses, residue returned to leases, etc., as shown in Exh. 224.

line Department, and the Oil and Gas Production Department. The Natural Gas Department operates all wells producing

dry gas only[16], and all gas gathering systems. The Natural Gasoline Department operates the gasoline plants. The Oil and Gas Production Department operates the 100 percent oil wells, and the joint product wells. The latter include: (a) wells producing both oil and casinghead gas, and (b) wells producing both condensate and condensate gas. In addition, several service departments perform services in connection with natural gas operations (56:7858-60). Out of the total of 375,690,912 Mcf of gas produced by Phillips in 1954, 226,681,178 Mcf was produced in the Natural Gas Department and 149,009,734 Mcf was produced in the Oil and Gas Production Department.

We now turn to a consideration of the specific cost-of-service problems involved in the instant proceeding.

IV. Phillips' Right to Sec. 5(a) Increases Under the Mobile and Sierra Pacific Doctrines

The annual rate increases provided for in Phillips' instant consolidated Sec. 4(e) rate filings (involving jurisdictional contracts which by their terms permitted price revisions under escalation clauses, or for other reasons), amount in the aggregate to $5¼ million—including increases in specific contract rates to levels ranging from as low as only 5.5 cents per Mcf to 13.5 cents per Mcf (with one increase to 17 cents per Mcf).

Phillips' prayer for relief in this proceeding, however, goes much farther than the $5¼ million increase reflected in such Sec. 4(e) dockets. In addition to requesting that the proposed rates contained in its Sec. 4(e) rate filings

[16] Also referred to as gas well gas.

should be found "just and reasonable" and that the Sec. 4(e) proceedings should therefore be terminated, relieving it from any obligation to make refund thereunder, Phillips also makes the following contentions: (a) that its total jurisdictional cost of service is $92,309,438 (Exh. 323, p. 1, line 5); (b) that its present revenues at November 1, 1956 prices (reflecting the consolidated Sec. 4(e) rate increases) are substantially below such cost of service; (c) that in order to eliminate such claimed deficiency Phillips must be allowed gross revenue increases amounting to $44,031,762[17] over and above its revenues at the November 1, 1956 prices (Exh. 324, Schedule I), and must be allowed rates ranging from a maximum of 22.75 cents per Mcf to a minimum of 16.50 cents per Mcf, depending upon delivery conditions.

Phillips accordingly requests the Examiner and the Commission to make a finding under Sec. 5(a) of the Act that unless it is permitted

to recover such rates and revenues, its rates will be so low as to adversely affect the public interest, and to impair its ability to continue its service, within the meaning of the Sec. 5(a) standard laid down by the U. S. Supreme Court in *Federal Power Commission* v. *Sierra Pacific Power Company*, 350 U. S. 348 (1956) (63: 8780-8782). Phillips' ultimate prayer for relief is that in the instant Docket G-1148 proceedings, the Examiner and the Commission should find that its jurisdictional rates are so low that they are not in the public interest, and that the necessary findings and order should therefore be issued permitting Phillips to file rates equal to its total claimed cost of service, it being contended that the specific rates recommended in its Exh. 324 are adequate and appropriate to accomplish this purpose (Phillips' reply brief, pp. 141-142).

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[17] Based on 1954 sales volumes.

It thus appears that if Phillips' total prayer for relief in the instant consolidated proceeding were granted, its annual jurisdictional revenues would be increased in an amount totalling approximately $49 million over and above the level of its revenues prior to the instant Sec. 4(e) rate filings.

It also appears that the $44 million annual increase sought here by Phillips solely on the basis of the requested Sec. 5(a) finding would, if granted, fall upon Phillips' various pipeline customers in the following distribution, based upon 1954 sales volumes:

El Paso	$12,500,109
Michigan-Wisconsin	12,212,496
Panhandle	8,161,586
Northern Natural	2,504,918
Permian Basin Pipe Line Co.	2,591,630
Texas Illinois Natural Gas Pipe Line Co.	1,793,576
Cities Service Gas Co.	1,134,143

The remaining customers would sustain increases under $1 million each (Exh. 363).

It may be noted that with respect to those jurisdictional contracts which, by their terms, do not presently authorize a price change by Phillips, we have a situation falling within the prohibition laid down by the Supreme Court in *United Gas Company* v. *Mobile Gas Corporation*, 350 U. S. 332 (1956), that under the Natural Gas Act a natural gas company has no power to change its contracts unilaterally. It is therefore clear that with respect to those contracts the Phillips rates cannot be changed unless the Commission here determines such contract rates to be so low as to conflict with the public interest—in which

case Phillips may be authorized under Sec. 5(a) to file schedules increasing those rates. Phillips itself recognizes

that this is the only avenue open for a rate increase under such contracts (63:8781-84), and contends that the instant record justifies and requires such a Sec. 5(a) determination.[18]

The standards which must be met in order to warrant such a Sec. 5(a) finding were set forth by the Supreme Court in the *Sierra Pacific* case, *supra*, decided on the same day as the *Mobile* case, and which similarly involved a unilateral rate increase filing. Although the *Sierra Pacific* case arose under Sections 205(e) and 206(a) of the Federal Power Act, those provisions, as noted in the introductory portion of the Court's decision, are substantially identical to Sections 4(e) and 5(a) of the Natural Gas Act. The Court held:

> "The condition precedent to the Commission's exercise of its power under Sec. 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential.' (350 U. S. at 353)
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> • • • • •
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> "In such circumstances the sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest—as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory.
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> • • • • •

[18] The conclusion that the Sec. 4(e) route is not available to Phillips in this situation is not affected by the recent decision of the Supreme Court in the *Memphis* case—*United Gas Pipe Line Company* v. *Memphis Light, Gas and Water Division, et al.*, (decision issued December 8, 1958). Unlike the pipeline contracts which were under consideration in the *Memphis* case, the Phillips contracts here contain a specified, fixed price for a term of years, and no general right was reserved to change such fixed price except pursuant to the terms of the specific escalation clauses therein contained.

"Whether under the facts of this case the contract rate is so low as to have an adverse effect on the public interest is of course a question to be determined in the first instance by the Commission." (350 U. S. at 355)

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However, with the exception of the Eastern Seaboard companies (Eastern), the interveners generally take the position in this proceeding that the instant record does not establish that Phillips' contract rates presently in effect are so low as to adversely affect the public interest by impairing its financial ability to continue service; that even in the event it should appear, on the basis of the jurisdictional cost of service determined in this proceeding, that approval merely of the Sec. 4(e) rate increases, and no more, would leave Phillips with a cost of service deficiency, the required findings to justify a Sec. 5(a) order still cannot be made here because Phillips has not been losing money on its gas operations and is not losing money on those operations today.

The Staff's reply brief strongly disagrees with this position, contending that the Phillips contract rates vary so widely, even as between contracts for the same service from the same producing areas, as to patently contravene the public interest, generating and perpetuating undue preference and undue discrimination; that this results in a rate structure completely adverse to the very principles and purposes of the Natural Gas Act; that the *Sierra Pacific* decision, *supra*, clearly recognizes the power of the Commission under Sec. 5(a) to modify contract rates in order to eliminate undue discrimination or preference; that accordingly the Examiner and the Commission should modify Phillips' contract rates in such a way as to eliminate such undue discrimination and preference, and that such modification when effected should permit Phillips

opportunity to obtain revenues from jurisdictional sales sufficient to meet its jurisdictional cost of service as determined in this proceeding.

The important factor to bear in mind here is that we are not in the instant proceeding dealing with a *single*, low-priced contract, as in the *Mobile* and *Sierra Pacific* cases, *supra*, but what is involved here is Phillips' entire jurisdictional rate structure. In the *Mobile* and *Sierra Pacific* cases, where only a single contract was involved, there obviously could be no contention that the failure to permit the pipeline seller to increase its existing rate on that one contract would impair its financial ability to continue its over-all service. In the instant proceeding, however, if the interveners' position were adopted Phillips would be required to absorb the burden of a substantial over-all cost-of-service deficiency, on a system-wide basis. In fact, the application of the intervenors' position in the instant case would produce the following concrete results:

(1) Phillips' rates for the contracts involved in the consolidated Sec. 4(e) dockets would be fixed on the basis of the cost-of-service herein determined. With respect to some of the Sec. 4(e) dockets, where the proposed rate level exceeds the "just and reasonable" rates here determined, this would mean rejection of a portion of the proposed rate increase.

(2) With respect to those contracts not involved in the instant Sec. 4(e) rate filings (hereafter referred to, for purpose of convenience, as the Sec. 5(a) contracts), in those cases where the existing contract rates exceed the "just and reasonable" rates here determined, a rate reduction would be required under the Sec. 5(a) order to be issued in this proceeding.

(3) However, with respect to those Sec. 5(a) contracts where the existing contract rates were, in fact, *lower* than the "just and reasonable" rates here determined, it would follow under the interveners' position that no relief could be provided to Phillips. And Phillips would thus be frozen in a situation where it would be compelled to absorb the resultant over-all system-wide deficiency, until such time as a price revision was authorized under the terms of such contracts—whether as the result of activation of an escalation provision, or a price renegotiation between the parties.

The Phillips reply brief (page 120) correctly characterizes such a situation as follows:

> "These Intervenors would thus convert *Sierra*, which held that the public interest may permit one sale at less than cost, into a decision that requires that all sales in total be at less than cost. Nothing in *Sierra* supports that conclusion."

It is concluded here that such a situation would adversely affect the public interest, in that (a) it would impair Phillips' financial ability to continue to render adequate service; (b) it would so impair the Phillips incentive for continued exploration and development as to jeopardize the continued program for the discovery of new gas reserves, which is essential to meet increasing market requirements; (c) it would result in an unduly discriminatory general rate structure for Phillips. It should further be noted that in the broader context of the entire problem of producer rate regulation now before the Commission, where the Commission is attempting to develop a reasonable, fair and workable system for the fixing of "just and reasonable" producer rates, the adoption of any such position would produce an unfair and discriminatory rate system which would clearly not be in the public interest. As well-stated by Phillips in its initial brief (page 173):

"The finding of a deficiency, without a corresponding finding that rates must be adequate to recover costs, would constitute a finding that it is in the public interest for a natural gas company to provide its services at less than cost. *If cost is to be the standard for rate regulation, a refusal to permit the recovery of costs under the circumstances here presented would be the clearest kind of confiscation.*" (emphasis supplied)

The interveners argue, however, that such a position actually would merely leave Phillips in the same price position it occupied prior to regulation, when it remained bound by the terms of its contracts until they were renegotiated by the parties. But this ignores an important part of the picture prior to regulation, because in the absence of regulation producers were free (a) to raise an existing contract price to the full level permitted under an escalation provision, or to the full level agreed upon in a price renegotiation, without limitation to the "just and reasonable" rate level determined by the Commission; and (b) to negotiate higher price levels in new contracts, without being subject to the possibility that the Commission might in a subsequent Sec. 5(a) proceeding order such new contract price reduced as being in excess of the "just and reasonable" rate. None of these "laissez faire" avenues remain open any longer to the producers since the Supreme Court's *Phillips* decision.

As noted above, the adoption of the interveners' position here would also result in an unduly *discriminatory* general rate structure for Phillips, and this alone is sufficient to warrant its rejection. As noted by the Supreme Court in the *Sierra Pacific* decision, contract rates may be set aside under Sec. 5(a) where they are found to be unduly discriminatory. (350 U.S. at 355).

The U. S. Court of Appeals for the District of Columbia Circuit dealt with this problem in *Mississippi River Fuel Corporation* v. *Federal Power Commission*, 252 F. 2d 619 (1957).[19] In that case United Gas Pipe Line Company sold natural gas to Mississippi River Fuel Corporation under two different contracts—i.e., (1) a 1929 contract, providing for a 45-cent demand charge and a 5-cent commodity charge; and (2) a 1951 contract, providing for a $1.30 demand charge and a 12.5-cent commodity charge. The Commission decision, issued in a Sec. 5(a) proceeding, fixed a single rate of 75-cent demand and 10-cent commodity charge for all sales by United in its Central Rate Zone, including both of these two sales to Mississippi. Mississippi contended, on appeal, that under the Supreme Court decisions in the *Mobile* and *Sierra Pacific* cases, until the Commission determined,

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upon a proper record, that the public interest required abrogation of the two existing Mississippi contracts, the separate contractual basis must be maintained; that the Commission was required to find specifically that the old contract rate of 45-cent demand and 5-cent commodity charge was itself unlawful before a change in that contract rate could be required.

The Court of Appeals rejected this contention and affirmed the order of the Commission on this point, stating:

> ". . . The Commission found . . . that continuance of two rates for the same service at the same point was not in the public interest and would result in unreasonable differences . . . The Commission has power under Section 5 (a) of the Natural Gas Act to determine a just and reasonable rate or contract affecting rates whenever it finds that an existing rate

[19] Certiorari denied 78 S. Ct. 331 (December 16, 1957).

or contract affecting rates is unjust, unreasonable, unduly discriminatory or preferential. In the case at bar the findings of the Commission were that the two rates on the separate contracts 'are not in the public interest', that the continued existence of two rate schedules would constitute 'maintenance of an unreasonable difference', and that compliance with Section 4 of the Act would be effected by a filing by United which would 'eliminate unjust, unreasonable and unduly discriminatory rates to Mississippi' and would apply to Mississippi the same rates applicable to other customers. We think these findings adequately met the statutory prescription for underlying findings in Section 5 (a)." (252 F. 2d at 623)

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"Mississippi argues that the Commission was required by the *Mobile* and *Sierra Pacific* cases, *supra*, to find specifically that the old contract rate of forty-five cents and five cents was itself unlawful before it could order it changed. *Those cases each dealt with a single existing contract.* The Court held that before the Commission could cause such a contract rate to be raised it must make the findings required by the statute. In the case at bar there are two existing contracts, one with a low rate and the other with a high one. The Commission did not find specifically that the low rate was unreasonable, etc. It found that the two contracts, with two rates, were not in the public interest and would maintain an unreasonable difference. It seems to us that the action of the Commission was within the scope of the statute and within the doctrine of the *Mobile* and *Sierra Pacific* cases, even though not within the factual bases of those opinions. We think that in a situation involving two contracts, at different prices, for different portions of

a single service, it is within the power of the Commission to combine the two contracts even though the combination results seemingly in a technical breach of the contractor's or the public's rights under the lower priced of the two contracts." (252 F. 2d at 624-25; emphasis supplied)

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"The whole action was to substitute a single rate for two separate rates found by the Commission to be unduly preferential. The Commission had a *positive duty* under the basic provisions of Section 5 (a) to eliminate preferential discriminations . . ." (252 F. 2d at 626; emphasis supplied)

There can be no doubt that the adoption of the interveners' position here would be far more seriously contrary to the public interest and would maintain a far more unreasonable and unwarranted difference in the Phillips jurisdictional rate structure than the two-contract situation which the Court of Appeals in the above case found to be within the power of the Commission to remedy under the standards of Section 5 (a).

It is therefore concluded that the controlling facts in the instant proceeding satisfy the Section 5 (a) standards as laid down by the Supreme Court in the *Mobile and Sierra Pacific* cases, *supra*, and that accordingly Phillips should be permitted to file rates sufficient to return its total jurisdictional cost of service, as determined in this decision. It should be noted, however, as will be made clear in the order to be entered herein, that with respect to the Section 5 (a) contracts no rates higher than Phillips' existing contract rates will become effective until after Phillips may file new rate schedules for such contracts pur-

suant to the instant order, and until the Commission approves any such new schedules as may thus be filed.

V. Summary of the Different Cost-of-Service Approaches in This Proceeding

Before proceeding to a point-by-point analysis of each of the contested issues in this proceeding, it would be helpful to set

forth at the outset, for purpose of comparison, a concise summary of the general cost-of-service approach followed by each of the parties presenting a comprehensive cost-of-service study in this case. All of these studies were presented on the basis of a 1954 test year.[20]

(1) The Phillips Cost of Service

The cost-of-service presentation relied on by Phillips in this proceeding is embodied in its Exhibits 282, 284 and 323.

In Exh. 282, Phillips' witness Cramer[21] presented the total cost of exploring for and producing crude oil, condensate and raw natural gas by Phillips and its wholly-owned subsidiaries. In addition, he showed the total cost of natural gas purchased by Phillips from others, the total cost of gathering the produced and purchased gas, including the extractable liquid hydrocarbons, and the cost of marketing the produced and purchased gas. Costs which could be associated directly with either crude oil and condensate or with natural gas were charged accord-

[20] At a later stage of the hearing, Phillips' witness Cramer presented a 1956 cost-of-service study (Exh. 303) solely for the purpose of demonstrating that the 1954 cost-of-service relied on by Phillips was, in fact, truly representative of the future (73:10,006).

[21] Senior Auditor in Phillips' Comptroller's Department.

ingly. The great bulk of the total costs, however, were joint costs which could not be associately directly with one product or the other and which accordingly were allocated on various bases. All costs were based upon 1954 as the test year, with certain proposed adjustments which Phillips contends are necessary to make the test year representative of the future. The rate base consisted of the year-end balances, the only adjustment here being the addition of the cost of construction of the Tex-Booster, a field compressor station constructed subsequent to the test year for the sole purpose of maintaining contracted volumes at the level delivered during the test year (60:8459-60).

Production costs (excluding exploration) were first determined by departments. Costs of dry gas production included all costs of the Natural Gas Department. Costs of production from joint product

leases in the Oil and Gas Production Department were allocated between oil and gas on the basis of the "relative cost" method. This method allocates the costs of producing oil and gas together, in proportion to the known costs of producing each separately (60:8461-5).

Exploration costs which can be attributed directly to either the Natural Gas Department or the Oil and Gas Production Department are so charged on Phillips' books. After giving effect to these charges, the balance of the exploration costs was then allocated between and assigned to those departments in proportion to the net investment in producing leaseholds of each department (59:8257-8), resulting in an allocation of 37.69 percent of such remaining exploration costs to the Natural Gas Department (Exh. 282, p. 14, line 2, col. 6).[22] Within the Oil and Gas

[22] After accounting for producing royalties, the amount remaining applicable to producing leases of the Natural Gas Department comprises approximately 34 percent of the total costs attributable to exploration operations (60:8481).

Production Department the sum of direct and allocated exploration costs was further allocated among the separate products in proportion to the total Btu's produced for each of the separate products (60:8464).

The production and exploration costs so determined for all gas produced by Phillips were then added to the purchased gas and gathering costs to determine a total cost for natural gas, including extractable liquid hydrocarbons. Costs associated with liquid hydrocarbons extracted by Phillips were then deducted under a combined volumetric and Btu allocation method. Costs of marketing the residue gas were then added, and the total costs of gas were then divided between jurisdictional and non-jurisdictional business in proportion to the volumes sold (60:8474).

Phillips' witness Cramer used a rate of return of 12 percent applied to year-end investment (60:8482). Federal income taxes were computed at the 52 percent rate, without reflecting the special deductions provided by the tax statutes, and taken advantage of by Phillips, for expensing of intangible drilling costs and percentage depletion (60:8483-4). To the total cost of service, Cramer added $400,000 for regulatory expense (60:8470).

Exh. 282 shows a total cost of service for jurisdictional sales of gas of approximately $82,000,000, reflecting only the claimed purchased gas cost increase adjustments related to the Sec. 4(e) rate filings, but not those relating to the requested Sec. 5(a) increases. This total cost of service would amount, on an average unit cost basis, to 16.707 cents per Mcf (Exh. 282, p. 1, line 5, col. (e)). Exh. 282 further shows revenue from jurisdictional sales of approximately $45,500,000 and a resulting deficiency between revenues and cost of service of approximately $36,500,000. That exhibit, however,

takes into account actual revenue and the Sec. 4(e) pro-

posed revenue increases only through January 1, 1956. Prior to November 1, 1956, Phillips filed additional Sec. 4(e) rate changes in dockets consolidated with this proceeding, providing additional revenues of approximately $2,738,000. The net claimed impact of these further Sec. 4(e) filings upon Phillips' cost of service and revenues is set forth in Exh. 284, and the two exhibits combined show a net claimed deficiency between revenues and cost of service of approximately $35,250,000.

It is to be borne in mind, however, that in Exhs. 282 and 284 Phillips reflected a claimed purchased gas cost increase adjustment computed only on the basis of its Sec. 4(e) filings. In its final presentation in this proceeding Phillips relies upon Exh. 323, showing a total jurisdictional cost of service of $92,309,438, computed on the basis of reflecting the claimed purchased gas cost increase which Phillips claims it would incur if it were allowed to recover its entire calculated jurisdictional cost of service, as a result of the Commission making the Sec. 5(a) findings here requested by Phillips. This total jurisdictional cost of service in the amount of $92,309,438 would amount to an average unit cost of 18.793 cents per Mcf (Exh. 323, p. 1, line 5, col. 3; Phillips, initial brief, p. 149).

(2) The Staff Cost of Service

The Staff did not determine costs for casinghead and condensate gas. Instead, the Staff in Exhs. 208 and 212, prepared by Staff witness Vaught, computed unit costs for dry gas by areas, and "imputed" the unit cost of producing dry gas in the Panhandle-Hugoton field to casinghead and condensate gas produced by Phillips' Oil and Gas Production Department in *all* areas. As a result, the Staff study does not constitute an allocation of total cost.

The Staff computed unit dry gas costs as follows: Staff costs were based upon recorded amounts for the year

1954, without reflecting Phillips' claimed adjustments for "known changes." The Staff accepted the direct charges to the Natural Gas Department for exploration as shown on Phillips' books (50:7172-3), but rejected the method used on Phillips' books for allocating the balance of exploration costs between departments on the basis of net investment in producing leaseholds. Instead, the Staff assigned 15 percent of the remaining exploration costs to the Natural Gas Department (44:6496). The exploration costs thus allocated to the Natural Gas Department were then included in the computation of the unit dry gas costs imputed to casinghead gas.

The dry gas costs thus calculated, including purchased gas and gathering costs, were allocated between natural gas and liquid hydro-

carbons extracted by Phillips on a relative value basis (45:6571-5), using settlement figures shown on Phillips' books for gas purchased by Phillips as the relative value between gas and liquids (49:7017). A rate of return of 9 percent was applied to a rate base consisting of an average of beginning and ending balances for the year 1954 (Exh. 208, Sched. 5, Sheet 1). With respect to the federal income tax component, the Staff's initial brief (pp. 113-121) takes the position that the computation should be made on the basis of Phillips' actual tax liability, reflecting both the statutory depletion and intangible well drilling allowances.

On this basis, the Staff concludes that Phillips is entitled to a total jurisdictional cost of service of $42,024,180 (p. 148 of Staff's initial brief) and this would amount to an average unit cost of service of 8.55 cents per Mcf.[23]

[23] $42,024,180, divided by 1954 jurisdictional sales volume of 491,178,953 Mcf.

(3) The Eastern Seaboard Intervenors' Cost of Service

The cost-of-service study presented by witness Caplan[24] on behalf of the Eastern Seaboard group appears in Exh. 388. Caplan used Cramer's relative cost method (but with some changes) for the purpose of allocating joint product well production cost in the Oil and Gas Production Department between gas and oil (100:13217). Direct exploration charges to departments by Phillips were accepted by Caplan, but remaining exploration costs were allocated directly between oil and gas on the basis of what he termed the "reserves added realization" method (RAR), without any preliminary allocation of such costs as between the Natural Gas Department and the Oil and Gas Production Department (Exh. 388, Sched. 28). Caplan then allocated total cost of exploration, production, gas purchases and gathering costs between natural gas and natural gas liquids extracted on the basis of what he termed a "modified sales realization" method (101:13303). Return was computed using a rate base consisting of an average of beginning and ending investment balances (Exh. 388, Sched. 31). No witness for the Eastern Seaboard group recommended a specific rate of return, but

for illustrative purposes only, Caplan showed the results of his study using three different rates of return of 6 percent, 9 percent, and 12 percent (Exh. 388, Sched. 40). In computing the income tax component, Caplan reflected the statutory depletion allowance, but did not reflect the expensing of intangible drilling costs (101:13305). He also used a higher interest expense deduction in computing income taxes than that used by Phillips (101:13304).

[24] Dr. Benjamin Caplan, formerly a member of the Staff of the Council of Economic Advisers in the Executive Office of the President, and subsequently Economic Adviser to the Economic Stabilization Agency. Dr. Caplan is presently associated with the firm of Boni, Watkins, Jason and Company in New York City, as a senior consultant.

On the basis outlined above, Caplan derived a total cost of service for jurisdictional sales of gas amounting to $55,046,180, or an average unit cost of 11.207 cents per Mcf with a 9 percent rate of return (Exh. 388, Sched. 40, p. 2, Col. (F), lines 6 and 7); and a total cost of service of $60,489,481, or an average unit cost of service of 12.315 cents per Mcf with a 12 percent rate of return (Exh. 388, Sched. 40, p. 3).

(4) The Wisconsin Cost of Service

The cost-of-service study presented by witness Van Scoyoc,[25] on behalf of the State of Wisconsin, Public Service Commission of Wisconsin and City of Detroit, Michigan, appears in Exh. 389. Production costs of Phillips' Oil and Gas Production Department were allocated between oil and gas on the basis of what Van Scoyoc terms the "separate products cost" method (Exh. 389, Sched. 11)—roughly similar to Cramer's "relative cost" method. Direct exploration charges to departments were not accepted by Van Scoyoc and were added back to the totals to be allocated (119:16064-5). Allocation of total, system-wide exploration costs between natural gas and crude oil and condensate was made in direct proportion to the net revenue of the various products, using actual income for oil and condensate liquids and cost of service as the income for gas before deducting expenses to arrive at net revenue (101:13386-7; 119:16061). Joint costs between natural gas and natural gas liquids were allocated on the basis of what Van Scoyoc termed the "single marketable products basis" (101:13359-64). Since the allocated cost of service for gas was used as the basis

[25] Melwood W. Van Scoyoc, formerly a member of the Federal Power Commission staff from 1938-1954, serving as Assistant Chief of the Bureau of Accounts, Finance and Rates from 1946-54—presently engaged in consulting work in the public utility field.

of allocation with respect to both exploration and natural gas liquids, the methods used by Van Scoyoc necessarily required multiple trials before arriving at the final figures (119:16062-4) Wisconsin takes the position that *average* year rate base should be used.[26] The rate of return em-

ployed was an assumed 7¾ percent (101:13369). In computing federal income taxes, both the statutory depletion and intangible well drilling allowances were reflected as deductions (101:13398).

On the basis above outlined, Van Scoyoc arrived at a total cost of service for jurisdictional sales of gas amounting to $48,647,832, or an average unit cost of 9.904 cents per Mcf.

In summary, it is of interest to note here, for purpose of comparison, that the four comprehensive cost-of-service studies presented in this proceeding produced the following results:

Party		Total Cost of Service for Jurisdictional Sales of Gas	Average Unit Cost per Mcf
Phillips		$92,309,438	18.793¢
FPC Staff		$42,024,180	8.55¢
Eastern	(at 9% rate of return)	$55,046,180	11.207¢
	(at 12% rate of return)	$60,489,481	12.315¢
Wisconsin		$48,647,832	9.904¢

This decision does not adopt, without modification, the total cost-of-service as presented by any one of the parties. However, for purpose of convenience, the cost-of-service here derived uses the Eastern cost-of-service study (Exh. 388) as its point of departure. Wherever there is a departure from the Eastern position on a given item, the

[26] However, Van Scoyoc, for comparative purposes only, used Cramer's year end figures in his Exh. 389 (Wisconsin initial brief, pp. 5-6).

appropriate recalculation, if deemed necessary for clarity, is set forth in a table contained in the Appendix at the end of this decision. In addition, wherever a given schedule in Exh. 388 contains figures which are affected by any such recalculations, that schedule has been reworked in an Appendix table.

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X. Allocation of Exploration Costs—Alternative Methods Considered in This Proceeding

The determination of Phillips' exploration costs[43] constitutes one of the most important issues in our entire cost-of-service study. The impact of this particular question is demonstrated by the fact that Phillips' total jurisdictional exploration costs (including exploration expenses, plus exploration return and related Federal income taxes) as computed by Cramer amount to $23,372,077, or 28.48 percent of Phillips' claimed (Exh. 282) total jurisdictional cost of service ((Exh. 388, Sched. 1-A, cols. (H) & (I), lines 8, plus 10, plus 13.)) Total exploration *expenses* (not including exploration return and taxes) amount to $15,016,511, or 18.3 percent of the total jurisdictional cost of service (Exh. 388, Sched. 1-A, line 8).

Although a minor portion of Phillips' exploration costs can be attributed directly to its Natural Gas Department, and therefore requires no allocation, the bulk of exploratory costs are by their inherent nature joint costs which must be allocated as between gas and oil. A substantial portion of the record and briefs in this proceeding was, ac-

[43] Throughout this discussion it will be helpful to bear in mind that where the term "exploration costs" is used, it includes exploration return and related taxes. Where the term "exploration expense" is used, these items are not included.

cordingly directed to the issue as to what allocation method should be adopted for this purpose.

In addition to the Staff approach, which has already been discussed, alternative methods for the allocation of exploration costs were presented by Phillips, Wisconsin, Pacific, Southern and Eastern. The following table[44] indicates the alternative methods proposed and the percentage of exploration costs allocable to gas under each:

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Allocation of Exploration Costs

Party	Allocation Basis	Allocated to Gas
Phillips	Net leasehold—Btu	61.88 percent
Wisconsin	Net revenue	20.82 percent
Pacific	Net contribution to earnings	23.98 percent
Southern	Successful wells	25.79 percent
Eastern	Reserves added realization (RAR)	30.46 percent

Because of the totally different approach employed by the Staff, as noted above, it is difficult to make a meaningful comparison of the Staff figures in this regard with those developed by the other parties. However, it is of some interest to note here that the Staff's initial brief (pg. 39) summarizes the effect of its method as allocating approximately $16,000,000 to natural gas exploration operations in the test year, and alleges that the comparable Phillips figure (based on Exh. 283) was approximately $34,000,000.[45]

Before proceeding to a detailed discussion of these alternative allocation methods, reference will be made to a few preliminary matters. No issue is raised as to the total amount of Phillips' exploration expenses for the

[44] Southern brief, page 25.

[45] These two figures, as cited by the Staff, represent jurisdictional exploration costs only (Staff's initial brief, Exh. A, sheet 2), whereas the exploration cost ratios set forth above reflect the exploration cost situation prior to the allocating out of liquid extraction costs and the costs attributable to non-jurisdictional gas sales.

test year 1954, calculated by Phillips at $47,474,039.[46] In addition, all parties have treated such exploration expenses as current charges, rather than as capital charges to be amortized.[47]

Southern complains of the fact that under the Phillips cost-of-service exploration costs are distributed on a pro-rata basis to all jurisdictional

sales, and are therefore equally reflected in the rates to be paid by all Phillips' customers without regard to whether deliveries to such customers consisted of gas actually produced by Phillips itself, or purchased by Phillips from other producers.[48] Southern objects to the fact that customers such as itself on the western part of the Phillips system would thus be required to pay in their rates a pro-rata portion of Phillips' total exploration costs, in spite of the fact that most of those costs were actually expended in southern and offshore Louisiana, and despite the fact that a relatively high portion of the gas delivered by Phillips from the Permian Basin area, which constitutes a major source of supply for its western system, consists of purchased gas.

It is concluded that the above position is without merit for the following reasons:

(1) The exploration activities carried out by Phillips in any major area are of ultimate long-range benefit and

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[46] The only differences were that the Staff figure was lower by $143,000, due primarily to its exclusion of Phillips' subsidiaries from the cost of service. In addition, with respect to that portion of the total figure representing land, geological and geophysical expenses, it has been noted earlier that Eastern witness Caplan took the developmental portion of this item out of "exploration expenses" and transferred it to "indirect lease expenses."

[47] Vaught, 50:7182-4, Caplan, 100:13,257; Cramer, 84:11,320; Wisconsin witness Colbert, 112:14896-8.

[48] In the test year 1954 approximately 52 percent of Phillips' gas supply was purchased by it from other producers (Exh. 224).

importance in connection with the problem of satisfying the supply requirements of its entire system.

(2) The situation complained of by Southern is balanced out by the fact that the Phillips purchased gas costs for that purchased gas which is actually delivered to its western system are also distributed on a pro-rata basis to customers in other parts of the Phillips system.

(3) The Southern position, if carried out to the ultimate degree, would require that the rates paid by any given Phillips customer should not reflect any costs not directly related to the gas actually delivered to such customer—including not only exploration costs, but production costs and other costs as well. The net result of such a position would be to require the making of multiple, separate cost-of-service studies, on a contract-by-contract basis. Such a procedure would be highly impracticable and undesirable, and is completely unnecessary to the determination of a fair and reasonable result in the public interest.

In response to the Phillips contentions as to the level of exploration cost allowance allegedly required to provide it with the necessary incentive for continued exploration and development, the briefs filed by Pacific and other interveners have stressed the fact that there is no assurance that any exploration funds made available to Phillips through rates approved in this proceeding will necessarily benefit its interstate gas customers; that any new reserves discovered as a result of

such exploration operations might be diverted by Phillips to intrastate uses, or that such funds could be used by Phillips for overseas exploration.[49]

[49] Phillips carries on a substantial level of exploration activity in other countries.

It seems clear, however, that if Phillips' jurisdictional rates are to be determined on the basis of a test year cost-of-service, then in the absence of compelling reasons to the contrary there must be reflected in such cost-of-service Phillips' actual test-year exploration costs, adjusted to reflect the appropriate allocation to non-jurisdictional sales.[50] Mere speculation that Phillips in future years could, if it so desired, devote a larger portion of its exploration expenditures to foreign operations, or could resell a larger percentage of its gas supply in intrastate commerce, cannot be regarded as a basis for departing from this general principle in the instant proceeding. Of course, if such a major change in the direction of Phillips' test-year operations should develop in the future, the Commission would always have the power to institute a new Sec. 5(a) rate investigation, in which a new cost-of-service study would then be developed reflecting such changes.

In addition to the above, it is relevant to note here that the Phillips policy witness in this proceeding, Mr. Learned, testified that the entire exploration allowance ultimately approved by the Commission in the cost of service to be adopted in this proceeding, including return allowed on exploration investment, would be used by Phillips:

> "... in an exploration and development program which would have for its purpose the finding, developing and marketing of sufficient new gas supplies to enable Phillips to maintain the service which it is now performing." (62:8678, 8680 and 8682)

Before proceeding now to discuss the various allocation methods which have here been proposed for the allocation of exploration costs, it will be helpful, at the outset, to indicate the breakdown of items which are included in ex-

[50] The procedure for making the allocation to non-jurisdictional sales, which is not the subject of dispute in this proceeding, will be outlined at a later point.

ploration expense and exploration investment. Cramer's Exh. 282, pg. 14, lists exploration expense as $28,109,927.27 (line 6). This total figure includes, among other things, the following items (Exh. 282, pg. 16):

Undeveloped lease rentals [51] .....$4,994,085 (line 5).
Expired and surrendered leases ...$9,479,898 (line 12).

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Dry holes exploration .....$11,306,964 (line 10).
Dry hole contribution .....$ 2,025,395 (line 11).

It is thus clear that the total exploration expense represents largely the costs of unsuccessful exploration—i.e., dry hole expense, and the expense for expired and surrendered leases.

Cramer's gross exploration investment figure was $98,992,143 (Exh. 282, pg. 15, Col. 8, line 12). Out of this total, $76,347,909 represented investment in undeveloped leases (pg. 15, Col. 8, line 9).

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B. *Year-End vs. Average Rate Base*

The only major issue with respect to rate base is whether it should be determined on the basis of year-end investment or upon the average of the test year. Phillips used the year-end investment. The Staff and interveners Eastern, Wisconsin, and Southern averaged the beginning and end of the test year, to obtain an average rate base. The difference between these two methods produces an impact of over $1,500,000 in the total cost of service.

[51] "Undeveloped lease rentals" represent delay rental expense charges paid in order to hold the undeveloped leaseholds (79:10,715-16).

The Staff and intervener argument against year-end rate base is that it weighs in for a full year the cost of plant additions made during the year, whereas the revenues and expenses against which the investment has been matched are not adjusted to reflect the operations of the facilities installed on a full year basis (101: 13,292-94; 13,370). Both Eastern and the Staff contend that the use of average rate base is consistent with prior Commission practice. In support of this contention, they cite a number of earlier Commission decisions in which average rate base was in fact used, but where the question did not develop as a contested issue and accordingly was not the subject of any analysis in the Commission decision.

In support of its position that year-end investment should be used, Phillips argues that its Exhibit 237 demonstrates that, both on an absolute basis and on the basis of net investment per unit sold, the Phillips net investment has been increasing substantially each year. It is accordingly contended that it is year-end investment, rather than average rate base, which is more representative of the future. The Phillips reply brief (p. 95, footnote 2 cites a number of Commission decisions (all prior to 1949) in which year-end investment was used. However, most of these decisions were issued in settlement cases, and none included any discussion of the problem.

Generally speaking, it would appear to be desirable to use average rate base, *provided* that the test-year relationship between average rate base and actual annual volumes of sale may be regarded as representative of the future. This was, in fact, the basic principle or criterion laid down by the Commission in two important cases where Commission policy on this issue was discussed in detail—i.e., Op. No. 258, *In the Matter of United Fuel Gas Company,* 12 F.P.C. 251 (1953); and *In the Matter of Otter Tail Power Company,* 8 F.P.C. 393 (1949).

In these two cases the Commission concluded, on the basis of the evidence there presented, that the test-year relationship between these two factors was a representative one, and accordingly average rate base was used.

In the *United Fuel Gas Company* case the Commission stated:

> "We do not believe that a rate base computed as of one point in time is necessarily a proper measure of the investment which produced revenues over a period of time or which will be required to produce a volume of annual sales by a company which has experienced and still anticipates growth at the rate recorded for United Fuel. Sales are made by means of a plant which changes frequently. A precise measure of the plant used to produce a specific annual sales volume would be an average of the daily plant balances for the year. Such precision is unnecessary in the ordinary case where additions are relatively small or evenly spaced, hence we have frequently used average monthly balances to derive an approximation of the average continuous plant investment during a test period. In the instant case, it appears that United Fuel made additions to plant uniformly throughout the year, and, consequently, an average of the beginning and ending plant balances gives a reasonable approximation of the average continuous plant balance." (12 F.P.C. 255-256)

However, after thus setting forth the general principle to be followed in the absence of unusual conditions requiring a different treatment, the Commission proceeded to state the proviso in the following language:

> "Underlying our method of matching investment with revenues, there is the implicit assumption that the pat-

> tern of the period chosen is representative of the future—that the size of the plant investment in a particular period is related to sales of such period and that this relationship is relatively constant, and will hold true for the future." (12 F.P.C. 256)

In the *United Fuel* case the proviso just quoted was not applicable because, as there noted by the Commission, it appeared that United Fuel's historic growth in total sales had closely paralleled its growth in plant. It further appeared that United Fuel intended to expand its system, and that it anticipated a steady growth in sales volumes. The Commission noted that if this historic trend continued, investment requirements per unit of sales might be expected to decline, rather than to increase over test period requirements—since the record indicated that average plant investment per annual sales volumes had gone down from 59 cents per Mcf in 1947 to 52 cents per Mcf

in 1951. It was thus apparent that in the light of this trend the ratio of average rate base to annual sales volumes would be even lower in subsequent years than during the test period, and it was accordingly inappropriate to match test-year volume of sales with year-end rate base, which was even higher than average rate base for that year.

Similarly, in the *Otter Tail Power Company* case, *supra*, there was no contention that investment requirements per unit of sales were increasing. The Commission therefore concluded that under the facts there noted the use of the averaging method was appropriate. However, the Commission stated:

> "In other cases depending upon the particular facts, we have considered the year-end balances as well as the yearly average balances for the test year. *It has been*

our aim to use the method which would more clearly represent the future experience as far as that could be determined." (8 F.P.C. 401 emphasis supplied)

An examination of the evidence in the instant case demonstrates that the relationship between Phillips' 1954 average investment and the 1954 actual annual volume of sales was *not*, in fact, representative of the future, since it appears that the ratio of net plant investment required per million Btu's produced and sold has been steadily increasing from 36.79 cents in 1951 to approximately 56.94 cents in 1956. (Exh. 237; 80: 10,797)[121] It thus appears that in order to maintain the same level of production which was experienced in 1954 a constantly higher investment is required. (80: 10,797-99)

Since it therefore seems clear that Phillips' 1954 relationship of sales volume to average rate base is not a representative one for the future, the problem here is to determine or develop a different relationship which would, in fact, be reasonably representative of the ratio between average rate base and actual annual volume of sales expected to pertain for 1955, 1956, and subsequent years. Accordingly, in considering the propriety of Phillips' use of 1954 year-end rate base and 1954 actual annual volume of sales in this case, our attention should be directed to whether the resultant ratio would be comparable to and in line with the relationship of average rate base to actual annual volume of sales experienced in 1955, 1956 and subsequent years.

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[121] In fact, with the sole exception of the year 1950 when a very slight drop was experienced, the net plant investment per million Btu's sold has increased steadily in every year commencing with 1946. It is recognized that the Exh. 237 figures are based upon total investment including oil and gas, and total sales including both products. However, this does not affect the point made here.

The answer to this factual question can be determined in a rough way, which is sufficient for our present purpose, by reference to the data contained in Exh. 237. Calculations based upon this data indicate that Phillips' 1955 *average* net plant investment per million Btu's sold[122] was 51.61 cents; that the 1956 figure was 54.60 cents; and that if the trend indicated by Exh. 237 were to continue, it could be expected that even higher ratios would be incurred for 1957 and the years immediately following. By contrast, the 1954 test year *average* net plant investment per million Btu's sold[123] was only 48.96 cents—a figure which clearly is *not* representative of the ratio prevailing for 1955 and 1956 and which can be expected to prevail for the ensuing years.

On the other hand, the 1954 *year-end* investment per million Btu's sold, being a ratio comparable to Phillips instant proposal to use 1954 year-end investment plus 1954 actual revenues, amounted to 51.81 cents. This figure is practically the same as the 1955 *average* net plant investment per million Btu's sold which amounted to 51.61 cents, and is, in fact, *lower* than the 1956 *average* net plant investment per million Btu's sold amounting to 54.60 cents. It is therefore concluded that the use of 1954 *year-end* investment, plus 1954 actual revenue, in the instant case *does* produce a result which can be regarded as reasonably representative of the relationship between average rate base and actual annual volume of sales for 1955, 1956 and ensuing years; that this is not true of the relationship between 1954 *average* rate

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[122] Obtained by adding 1954 and 1955 year-end investment, and dividing by two; then relating the resultant figure to the 1955 volume of production sold.

[123] Involving a ratio comparable to the Staff and interveners' proposal to use 1954 average rate base plus 1954 actual revenues.

base and 1954 actual revenues; that accordingly the Phillips rate base in the instant case should be computed on the basis of year-end rate base.[124]

In reaching this conclusion, it is of interest to note the position taken in similar situations by State regulatory commissions in recent years. *In the Matter of Potomac Electric Power Company*, 8 PUR 3rd 76 (1955) was a rate case before the District of Columbia Public Utilities Commission. The Commission noted that the uncontroverted evidence submitted by the company indicated that it had been and would be compelled to make extensive additions to its facilities to keep pace with the constantly growing demand for power within its service

area, and that increases in earnings from new facilities had not kept pace with the related increases in investment. Under these circumstances, the company contended that instead of using average investment for the preceding year as a rate base, the net investment at the end of the year should be adopted as the base for the purpose of determining its allowable earnings. The D. C. Commission agreed with this contention, stating:

> Since rate making is geared to the future, from a theoretical standpoint both the investment and revenue figures should be projected. Because of the serious elements of speculation and uncertainty which often are injected by such an attempt at projection, however, it has been a usual practice to employ actual or adjusted past figures for both investment and revenues. This is justified normally by the fact that increases in plant may be expected to result in approximately

[124] For recalculation of the Phillips rate base on the basis of year-end investment, see Appendix Table 2.

proportional increases in revenues so that an appropriate allowance for future investment is automatically provided. So long as this expectation is regarded as sound it is essential, of course, that corresponding figures be used for revenues and rate base, or, in other words, that the rate base represent the plant which produce the revenues for the period taken. Since the investment in plant varies throughout any revenue period, this is accomplished by taking a weighted net average during the period.

"The premise that increases in plant produce an approximately proportionate increase in revenues loses validity, however, when large new investments must be made at prices sharply higher than the average cost of existing plant. To provide a rough counter-balance for this 'attrition' in earnings a considerable number of regulatory bodies have permitted the use of 'end of period' rather than 'weighted average' rate bases in appropriate cases. . . . For this same reason we have concluded that it is reasonable to adopt 'end of year' rate base in the present proceeding. In so concluding, however, we must emphasize that it is a deviation from what might be regarded as the proper standard under more normal conditions, and our action is not to be construed as furnishing a precedent in the case of other companies not faced with the same combination of circumstances or in the case of PEPCO itself when the present extraordinary situation shall have been altered." (8 PUR 3rd, at 89-90)

In the Matter of Florida Power Corporation, 99 PUR (NS) 129 (1953) was a rate case before the Florida Railroad and Public Utilities Commission. The Commission held:

"In normal times and under stable conditions the amount of revenue required to produce a fair rate of return can generally be calculated accurately and equitably upon the average and not the year-end balances of the test year. On the other hand, where a utility is in the throes of

unusual growth and confronted at the same time with constantly increasing investment and operating costs, conventional notions of rate making must be adjusted to the circumstances and this is especially true where net earnings fail to keep pace with heavy additions made and to be made in plant investment. Where there is little fluctuation in a utility's investment accounts from the beginning of the year to the end of the year, we believe that the rate base should be predicated upon the net average investment for the test period. We have followed that method consistently for many years and will continue to do so whenever and wherever the investment accounts disclose nothing more than a normal growth. In the present case, a net average investment rate base for the test year 1952 would be $76,000,000 in round figures whereas the utility at the end of 1952 had more than $95,000,000 invested in electric plant. If we use the average investment for the year 1952 in determining the rate base, we would assume an investment level that is more than a year old. Such a rate base would bear no relationship to the actual conditions as they now exist. There seems to be only one sound objection to the use of the year-end rate base and that is that some additional revenues must be ascribed to plant additions; however, this would be largely offset by the factors of additional depreciation, taxes, and expenses, so that there is little,

if any, danger of excessive compensation. Under present conditions, as disclosed by the record herein, we conclude that the year-end rate base is more realistic than the average investment rate base. Inasmuch as we are here fixing rates for the present and for a reasonable time in the future, we should not use an investment figure that is already more than a year old. During a period of rapidly rising prices and plant expansion, it is difficult, in proceedings of this nature, to determine an adequate and reasonable rate base. We must be fair to the public and exercise our rate-making power in such a way that the public is protected against exorbitant or unreasonably high rates. At the same time, the interest of the utility, and those who invest in its securities, must also be protected against noncompensatory rates." (99 PUR (NS), at 134-135)[125]

XIII — Adjustments to Test Year

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B. *The Contention that Phillips' Investment in the San Juan Facilities Should be Excluded from Rate Base*

As already noted in detail in connection with our discussion of Caplan's royalty adjustment under his RAR method, Phillips transferred its San Juan properties to Pacific Northwest Pipeline Corpora-

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tion in November 1955. Interveners Southern and Wisconsin contend that this transfer constituted a "known change" which should be reflected as a downward adjust-

[125] Similarly, see *Board of Supervisors* v. *Virginia Electric and Power Co.*, 196 Va. 1102, 87 SE 2nd 139, 150; *Western Light and Telephone Co.*, 17 PUR 3rd 422, 425.

ment to Phillips' test year rate base. (Southern initial brief, pp. 11-12; Wisconsin reply brief, p. 11). It may be noted that the total San Juan investment, amounting to $11,537,444, includes San Juan exploration assets in the amount of $3,106,686. (Exh. 346, sheet 3) This latter item has already been allocated out of Phillips' jurisdictional cost of service under the Caplan RAR method, which has here been adopted, since he allocated an appropriate portion of total exploration investment to royalty gas. If the position here advanced by Southern and Wisconsin were adopted, it would require a further reduction of the Caplan-computed rate base by slightly over $8,000,000, representing Phillips' net investment in San Juan producing leases. (Ex. 346, sheet 3)

The fallacy in the interveners' position here is that it treats the situation as one in which San Juan acreage was disposed of in 1955, and in which no additional leaseholds took their place. This however, was not the case. Phillips' policy witness Learned testified, in this connection, with reference to the 1955 sale of the San Juan acreage:

> "I can only say that we have probably already considerably more than reinvested the funds that came from that sale. They were a reasonably small amount and the override has been very small up to date. I don't think there is a question in the world but what they have already been reinvested." (92: 12,460-61)

In addition, Phillips witness Cramer testified:

> "All the way through I have been concerned about whether or not the cost of service study which I have prepared in connection with the year 1954, and as an adjustment that I had made, and including the investment in the San Juan leases and expenses and revenues that we are now talking about, of whether

or not that was truly representative of the future.

"I was aware that we had—although we had sold these properties that we had acquired other properties, and if I were going to take one out then I probably would need to consider including others that had been acquired, so that is . . ."

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"That was the reason that I was anxious to prepare an experimental test year for the year 1956 which has the San Juan properties out so far as the investment and expenses. It has all of the other changes that have

occurred, including the small drop in the direct dry hole expense that Mr. Lamb referred to yesterday, and *as a result of that experimental test year, and knowing the results thereof, I concluded that the cost of service study as I had prepared it, including the adjustments and including San Juan, was representative of the future as tested by the year 1956.*" (73: 10,006, lines 2-23; emphasis supplied)

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"Again, with respect to the San Juan, the company is constantly acquiring additional properties and maybe from time to time relinquishing the ownership of others, and knowing the magnitude of the additional properties that had been acquired after the year 1954 it seemed to me that it was unnecessary to make an adjustment with respect to San Juan.

"Now, for example, the natural gas departments rate base, or net investment at the end of 1954, was approximately 130 million dollars, but after removing the San Juan properties that were adjusted out in

November of 1955, and the additions to the gas department's properties in the year 1955, not only replaced the San Juan, dollar for dollar, but added some seven million dollars to the net investment over and above the depreciation and depletion that was recorded in the year, also." (73: 10,007, lines 11-25)

Southern notes the fact that the San Juan properties, which were included in the Phillips rate base for the test year in the amount of approximately $11,500,000, actually produced only $141,968 of jurisdictional revenues during that year. The Southern brief suggests that it would be unfair to include these properties in Phillips' rate base in view of the fact that the test year revenues received therefrom were insignificant, and that the properties were disposed of by Phillips as soon as they commenced to earn substantial revenues. The same argument, of course, could be made for the exclusion from Phillips' test year rate base of other undeveloped leaseholds which produced little or no revenue during the test period. However, this argument is not regarded as impressive, since it is not unusual for a substantial time lag to occur before potentially valuable leaseholds acquired by a producer in the normal course of business commence to produce and earn revenue. If this practice were not followed, the continual development of new reserves which is of such importance to consumers would be seriously hampered.

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In the "spiral escalation" contract situation Phillips purchases *dry gas* from certain producer-suppliers under contracts providing a fixed rate. However, these contracts contain spiral escalation clauses which are triggered by the going into effect of a similar spiral escalation clause in

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Phillips' resale contract with Michigan Wisconsin (Phillips FPC Gas Rate Schedule No. 4, *supra*).

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XIX. The Phillips Presentation Under the Heading of "The Consumers' Need for Gas and the Producers' Increasing Problem of Supply"

Phillips devoted a great amount of time in the hearing and in its instant briefs[175] to the painting of a pessimistic picture concerning the economic, geological and engineering aspects of our national gas supply. This presentation stressed the following points:

(1) The rapidly increasing demand for natural gas, and the alleged failure of discoveries to keep pace with such demand.

(2) The increasing depth of drilling resulting in increasing drilling costs.

(3) Rising exploration expenditures.

(4) Decreasing discoveries per million feet of hole drilled.

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(5) Declining ratio of net earnings to net investment in total gas and oil production.

(6) Increasing gas-oil ratios, making the producer more dependent than formerly upon income from gas.

Among other things, the Phillips presentation on these subjects would appear to be designed as a justification for its proposed allocation of approximately 60 percent

[175] Initial brief, pp. 8-41; reply brief, pp. 4-27.

of its total exploration costs to natural gas, as distinguished from oil—this being an allocation as to which Phillips itself states:

> "At first glance, the total amount charged to gas and natural gas liquids may appear large." (initial brief, p. 112)

The presentation appears also to have been advanced as a justification for the high rate of return here proposed by Phillips.

In general, the evidence presented on these subjects seems calculated to create the impression that the future prospects for finding necessary supplies of natural gas are so unpromising that the consumers must pay for an extremely high portion of exploration costs, as a sort of incentive or bonus necessary to call forth natural gas supplies in quantities sufficient to meet projected demands. Thus the Phillips exhibits and testimony in this connection embody complaints about the hazards of and the meager returns from exploration and development, and they attempt to lay the groundwork for the imposition of relatively high cost burdens upon the consumer by suggesting that if we are to meet future demands for natural gas "enormous discovery rates must be reached and maintained".[176]

We now turn to a point-by-point examination of the Phillips presentation on these subjects. It may be noted at the outset that Eastern presented a detailed rebuttal to this presentation through its witness, Dr. Alfred Kahn.[177]

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[176] Phillips witness Turner, 65: 8918.

[177] Professor of Economics at Cornell University, and a member of the Cornell faculty for the past ten years. Dr. Kahn served as Senior Staff Member on the President's Council of Economic Advisers in the year 1955-1956, acting as adviser on natural gas legislation. He is also a special consultant to the New York firm of Boni, Watkins, Jason & Company.

A. *The Phillips Contention as to the Rapidly Increasing Demand for Natural Gas, and the Alleged Failure of Discoveries to Keep Pace with Such Demand.*

Phillips witness Turner testified that in spite of the continued growth of proved gas reserves, enormous gas demands have caused the national life index, or reserves-production ratio,[178] to decline without interruption from 32.5 years at the end of 1946, to 22.1 years at the beginning of 1955, and to 21.8 years at the end of 1956. (Exh. 251, Panel A; Exh. 390, Sched. 1, 57; 8062; 102: 13,445)

It should be noted at the outset the concept of a 22-year life index does not mean that our national gas supply will be exhausted 22 years from now, since it does not take into consideration the reserves of natural gas to be found in the future, which will constitute by far the greater portion of our future supplies. Dr. Kahn testified:

> "Such uses of life-index figures are usually accompanied by statements . . . to the effect that by far the greater proportion of future supplies will come not from presently estimated proved reserves, but from supplies yet to be found and proved in the future. To the extent that industry sources minimize the significance of the life-index ratios, therefore, they do so not on the ground that the ratio is excessively reassuring, because of its failure to take into account the period of deliverability, but on the ground that it places excessive emphasis on the relatively small portion of total future supplies that has so far been found." (118; 15,914, line 19—15,915, line 5)

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[178] The mathematical ratio of current total reserves, to current annual volume of production.

Similarly, a report of the National Petroleum Council to the Department of the Interior, dated January 29, 1952, stated:

> "Frequently, the proved reserves are compared with the current annual production to arrive at the number of years that supplies will last. By such calculation it would have seemed almost any time in the past that supplies could last only ten to twenty years. On this basis there have been many predictions that we are running out of oil. Such predictions are nonsense today, because they fail to consider the rate of oil finding and development. It is future supplies, not presently known reserves, that will determine available supplies for the long run." (102: 13,453, line 22—13,454, line 7)

This statement, of course, is equally applicable to natural gas finding and development.

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Dr. Kahn testified that the seemingly sharp drop in the life index since 1946 was actually not as significant as suggested; that the 1946 life index of 32.5 years represented a historical peak, resulting from accumulating reserves of dry gas in the period before World War II and continued discoveries incident to the search for oil—all in the face of an only gently increasing demand for gas. This abnormal upward thrust was thereafter reversed as the result of a sudden acceleration in the expansion of demand due to the development of long-distance pipelines and interstate markets in the post-war period, giving rise to an enormous increase in total production. In the immediate post-war period 1946-1951, marketed production increased by an average of 13.1 percent annually, representing the highest rate of increase in the past thirty years. Dr. Kahn pointed out

that it is now generally agreed in the industry that the *growth rate* of demand for the past ten years will not be maintained.[179] The Chase Manhattan Bank contemplates an average increase in the production of natural gas during the next decade of only 4.7 percent per year, and this was approximately the growth rate assumed by Phillips witness Turner in his Exh. 293. The President's Materials Policy Commission [180] forecasts an average annual growth rate of 3.6 percent for the production of gas through 1975. It will be observed that these estimated rates of growth for the next decade are considerably lower than the average experienced in any of the five-year periods since 1926, or in any of the six-year periods since 1932. (pp. A1 and A3 of the Appendix to Phillips' initial brief) Thus although it is not denied by Dr. Kahn that there will be a continued increase in the *absolute level* of demand for natural gas, the *rate of growth* of demand is tapering off, and he concluded that this forecasts a similar tapering off in the decline of the life index. (102:13,446-49)

Turner estimated that the demand for natural gas would increase from the actual demand of 10 trillion cubic feet per year in 1955 to 15 trillion cubic feet per year in 1965. (Exh. 251, Panel B; 8915-16)[181] Based upon the estimated increasing demand, he concluded that in order to maintain our present 22-year life index, annual average additions to reserves should amount to 23.6 trillion cubic feet per year for the next nine-year period, as compared with an annual average of 16 trillion cubic feet found during the preceding nine-year period. (115: 15,367)

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[179] Phillips itself states, at p. 10 of its initial brief: "We agree with Kahn that the percentage rates of increase in demand will not be maintained."

[180] Referred to as the Paley Commission.

[181] Dr. Kahn accepted these figures. (Exh. 390, Sched. 4; 115: 15,365)

It should be noted here that all of Turner's conclusions with respect to the national gas supply picture are based upon his unsupported assumption that maintenance of the current 22-year life index is an essential objective. Dr. Kahn, on the other hand, based his studies upon the objective of maintaining a 20-year life index, explaining that this was based upon such factors as: (1) the common practice of underwriters to require that a pipeline company have twenty years' supply under contract before they will underwrite pipeline debt; (2) the practice of the Federal Power Commission, with respect to new major pipelines, to require an estimated life index of twenty years. (102: 13,451)[182] Since a life index of twenty years has been regarded by the Commission as an adequate criterion in evaluating the adequacy of gas supply in pipeline certificate cases, it is difficult to see why our instant evaluation of the national gas supply picture should be based upon the use of a 22-year life index as an essential measuring stick.

In Exh. 390, (Sched. 4, Col. 4) Dr. Kahn set forth his calculations as to the annual additions to reserves which would be required from 1957 to 1965 in order to maintain a 20-year life index, assuming Turner's estimated demands for each of those years. These estimated requirements, for this period, amounted to a required annual average addition of 22.8 trillion cubic feet. Although the average annual additions actually experienced for the period 1948-1956 amounted to 16.2 trillion cubic feet, the annual average of new supplies went up from 14 trillion cubic feet for the period 1946-1949, to over 19 trillion cubic feet for the period 1953-1956.[183] It further appears that in 1956 and 1957 alone,

[182] Dr. Kahn further noted, in this connection, that with respect to established pipeline companies even this standard had been considerably relaxed by the Commission since 1948.

[183] As will be noted shortly, the average for this latter period was distorted in a downward direction by the inclusion of the abnormally low year of 1954.

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23.5 trillion cubic feet per year were added on the average, culminating in an actual addition to reserves amounting to 24.8 trillion cubic feet for the year 1956 (Exh. 390, Sched. 1; 118: 15,889-90) Dr. Kahn estimated that, based upon Turner's estimated demands for the future, this last figure would not have to be exceeded until 1965, when a new supply amounting to 27 trillion cubic feet would be required. In view of the recent trend, as outlined above, Dr. Kahn did not regard the 22.8 trillion cubic feet annual average, required for the ensuing years in order to maintain a 20-year life index, as constituting a serious problem.

Dr. Kahn's Sched. 4 (Exh. 390) similarly indicated that, based upon Turner's estimated demands for the years 1957-1965, in order to maintain a 20-year life index the finding rate (or growth factor) for those years would have to amount to an annual average of 1.75. (Sched. 4, Col. 5)[184]

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Turning to the question as to whether it could reasonably be anticipated that these goals would be achieved in the years to come, Phillips witness Turner took a pessimistic view of the situation, based upon the finding rates actually experienced during the preceding decade, which he characterized as indicating a declining growth factor trend. He stated:

> "In spite of the continued growth of proved gas reserves, the enormous gas demands caused the gas reserves-production ratio to decline without interruption from 32.5 to 22.1, and the growth factor to decrease from 2.12 average for 1947 and '48, to 1.62 average for 1954 and 1955." (57: 8062)

Dr. Kahn, however, contended that this created a totally erroneous and misleading impression. He pointed out that

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[184] The finding rate, or growth factor, represents the ratio of annual reserves added, to annual production.

both he and Turner had used the same figures, but that the apparent decline in the growth factor as presented by Turner resulted exclusively from the fact that Turner had included in his 1954-55 terminal average the year 1954, which showed an abnormally and unrepresentatively low finding rate of 1.02. (Exh. 390, Sched. 1) Dr. Kahn explained that this unusually low finding rate for 1954 resulted from the fact that in that year [185] there was a sharp downward revision of the prior natural gas reserve estimates made in many states, combined with lower than usual upward revisions in other states; that this produced an unprecedentedly low nation-wide figure for "extensions and revisions", which constitute a large percentage of "new supply". (Exh. 390, Sched. 1, Cols. 1, 2 and 3) As a result, the extensions and revisions for 1954 were only 61 percent as high as those for the next lowest year in the post-war period. (*i.e.*, 1947). They were only one-third to one-fifth as high as the extensions and revisions for the years 1953, 1955 and 1956. (102: 13,443; 115: 15,319) He explained that the 1954 extensions and revisions were "of an extraordinary character"; that in order to test this conclusion, he had made a detailed step-by-step breakdown of these figures for 1954, obtaining the following results:

(1) Negative extensions and revisions (i.e., downward estimates) amounted to 7.76 percent of positive extensions and revisions in 1947; 1948—2.25 percent; 1949—1.60 percent; 1950—1.65 percent; 1951—0; 1952—0; 1953—1.31 percent.

(2) However, in 1954 negative extensions and revisions shot up to 20.24 percent.

(3) Thereafter, the ratios dropped down again to 0.02 percent in 1955 and 0.15 percent in 1956.

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[185] The year of the Supreme Court's *Phillips* decision, *supra*.

It is concluded that the data set forth above demonstrates beyond contradiction that 1954 was an atypical and completely unrepresentative year.

Dr. Kahn then noted that the eleven-year post-war period from 1946-1956 showed an average growth factor of 2.09. He concluded that this period included two atypical years—(1) the year 1954, which was atypically low; (2) the year 1946, which was atypically high, with a growth factor of 3.59. He accordingly eliminated both of these atypical years from the average of the post-war period, obtaining an adjusted average growth factor ratio of 2.04 for that period. (102: 13,442-43) He then further noted that aside from the atypical year 1954, the growth factor had fallen below 1.66 in only one post-war year, and that the ratio was 2.28 in 1956, the most recent year on record. This was the highest growth factor ratio experienced since 1948, reflecting the greatest increase in reserves in our post-war history. Based upon the above studies, Dr. Kahn concluded that the average annual growth factor rate experienced during the past decade (adjusted as indicated above) was 2.04; that on the basis of his estimate that an annual average finding rate of 1.75 would be required in order to maintain a 20-year life index for the nine-year period 1957-65 (assuming Turner's estimated demands for this period), the desired 20-year life index could be successfully maintained with finding rates, or growth factors, lower than those already experienced in recent years.

Phillips witness Turner, however, stresses the fact that in order to arrive at any realistic conclusions with respect to the gas supply situation, it is necessary to direct our attention not only to such matters as the national life index, but also to deliverability problems. It is recognized that, due to inherent deliverability problems, the life index, of course, does not constitute a measure of the reserves that

can actually be *delivered* within the stated number of years. (118: 15,913) This problem arises because of the fact that when production from a given well or reservoir reaches a certain point, the well or reservoir will thereafter produce only at a declining rate until it is completely exhausted—although it also means that production will stretch out for a longer number of years than the life index period. Turner used the term "breaking point" as the point at which the gas from a given reserve, due to deliverability problems, can no longer be produced at the given rate. He used the term "breaking point interim" to describe the period of years remaining before such breaking point would be reached, assuming that no new reserves were discovered and that production were to continue at the current rate. He then concluded that, based upon our current total national reserves and the current annual rate of production, our present national life index of 22 years is sufficient to maintain a 14-year breaking point interim, and that it is essential that such a 14-year breaking point interim should always be maintained.

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The only rationale submitted by Turner in support of this position was his statement that:

> "In my opinion so long as we continue to make investments in pipeline and distributing facilities we will be in an unhealthy position whenever we let that interim become less than it is now." (70: 9669-70)

Actually, it is clear that Turner's selection of a 14-year breaking point interim as an essential requirement was based upon his assumption that maintenance of the current 22-year life index is an essential objective. However, as already noted, it has here been concluded that no persuasive reason has been shown as to why the conventional 20-year life index should not be used as the yardstick.

Turner's next contention was that although our current 22-year life index is sufficient *at this time* to maintain the current production rate for 14 years, he does not expect this situation to continue in the future. His theory here was that the maintenance of the 14-year breaking point interim along with the 22-year life index "depends upon the national deliverability maintaining its present relationship to reserves"; that so long as this relationship is maintained, the breaking point interim will be extended proportionately as the reserves-production ratio is extended. (65: 8918, lines 12-17)

However, he concluded that, because of four different factors listed by him, the national deliverability in fact will not maintain as high a ratio or relationship to reserves as it now reflects. (65:8918, lines 17-19) Because of these pessimistic assumptions, Turner finally concluded that in order to maintain our present 14-year breaking point interim, it would be necessary to maintain a 1.5 growth factor even if demand were to remain constant at its present level; but that, based upon his estimated increasing demands, an even higher growth factor of 1.9 would be required. He stated in this connection:

> "In brief, if the estimated increasing demands are to be supplied, enormous discovery rates must be reached and maintained and the average annual discovery rate must be about 1.9 times the average annual withdrawal rate." (65: 8918, lines 3-6; 8924, lines 19-22)

As just noted above, these final pessimistic Turner conclusions are based upon his assumption that the national deliverability will not maintain its current relationship to reserves. This assumption was based, in turn, upon the following four factors, set forth by him in some detail:

(1) He concluded that

> " a very large portion of our present production is from reservoirs which have declined to a point of very low deliverability. In other words, we have become a nation of partially depleted reservoirs." (65: 8921, lines 5-8)

While listing this as a significant problem, Turner ignored the fact that by far the greater proportion of our future supplies of natural gas will come not from presently estimated proved reserves, but from supplies yet to be found and proved in the future. (118: 15,914-15) Since our future requirements will therefore be met in increasing degree from newly discovered reservoirs whose deliverability will be relatively high, the problem here raised by Turner does not appear to be significant.

(2) The next factor listed by Turner is that a large volume of the reserves now estimated to be recoverable will not be available

> "due to uses in the field for which no account is taken either in the estimate of recoverable reserves or in the estimate of markets. This is the gas used as fuel in pressure maintenance, gas cycling, and other reinjection operations." (65: 8921, line 17)

(3) The third factor is based upon his contention "that we are finding smaller and smaller fields". (65: 8923, line 8)

(4) His fourth factor is based upon the contention that

> "As we have drilled deeper and deeper and particularly as we have begun to develop off-shore, in deep and extremely high pressure reservoirs, the industry has continued to have occurrences of blow-outs and losses of

wells, equipment and gas. So far there is no indication that we can ever come close to eliminating all of these losses." (65: 8924, line 6)

It is important to note here that all of the four factors referred to by Turner, as outlined above, are highly speculative in nature. Although they raise problems which *may* be encountered, he completely failed to recognize or suggest any of the natural counterbalancing factors which may just as reasonably be speculated upon as possible ultimate solutions to minimize the effects of such problems. A good example of this flaw in the Turner presentation will be bound with reference to his fourth factor, *supra*, where, referring to the problem of blow-outs encountered in connection with off-shore drilling, he stated:

"So far there is no indication that we can ever come close to eliminating all of these losses."

This statement, of course, ignores the basic fact that off-shore drilling represents a relatively recent development in the petroleum industry. The history of this industry has indicated a high level of ability to meet its developing problems, both those of a technological nature and in other areas. It would seem totally unrealistic, and indicative of an unwarranted lack of confidence in the industry, to fail to recognize that as greater experience is had in the problems of off-shore drilling, new technological advances will undoubtedly contribute to a minimizing of such problems.

In connection with his discussion of the four factors listed above, Turner stated:

". . . we have no way of knowing that the discovery in any year of a volume of reserves equal to the volume produced during that year will maintain the national deliverability. I know of no way to calculate the effect

but, in my judgment, in the present status of withdrawals in the nation, something more than one for one discovery rate or growth factor is required for this cause alone." (65: 8921, lines 10-16)

It is interesting to observe that, after thus conceding that he knew of no way to calculate the effect of these problems, Turner proceeded to lay down as a precise rule that, due to these very factors, it is essential to maintain a 1.9 growth factor, or finding rate, on the basis of his estimated increasing demands.

It is concluded that the type of speculation thus indulged in by Turner does not provide a satisfactory basis for drawing any meaningful and fair conclusions as to the problem here under consideration. However, if any weight whatsoever were to be given to the Turner speculations, pitched in a pessimistic direction, it would become necessary to indulge in equally meaningful speculations pitched in the opposite direction, in order to provide a more balanced perspective with respect to the entire question of our national gas supply. In this connection, it would seem equally justifiable to take into consideration the following matters:

(1) *The Possibilities Inherent in Off-shore Drilling.* Eastern contends that the results of off-shore drilling to date suggest "a particularly bright outlook for future reserves". (initial brief, pp. 9-10) It appears that, although it has been estimated that the average off-shore well, including dry holes, has cost eight or nine times as much as the average on-shore well, it has, on the other hand, found eight to nine times as many reserves. (102: 13,462, 13,464) It appears that off-shore drilling expenditures made up to the end of 1956 had already proved out an estimated four trillion cubic feet of gas, and it had been estimated that it was entirely possible that discoveries made up to the end of 1957 would ultimately provide an off-shore reserve amounting to 14 trillion cubic feet of natural gas. (118: 15,885)

During cross-examination of Dr. Kahn on this subject, Phillips counsel directed attention to the high finding costs of off-shore discoveries, amounting to $14 per barrel of crude oil. Dr. Kahn, however, criticized this figure as "an accounting monstrosity". (118: 15,884, lines 20-21) He explained that this figure was obtained by dividing the aggregate capital expenditures off-shore by aggregate production to date; that the resulting figure was naturally unrepresentatively high, because it reflected high initial cost of investments thus far made which, although they had established production *capacity*, had not as yet borne fruit in correspondingly large current production. He suggested that if current estimates of the possible ultimate recovery of upwards of 1.75 billion barrels of liquids should prove sound, the finding costs might ultimately turn out to be less than $1.00 per barrel (even if it were assumed that the *gas* discovered had no value whatsoever).[186]

It is recognized that the data presented in the instant record with respect to the current results and estimated potential of off-shore drilling is too meager to provide the basis for anything more than speculative conclusions. However, it is sufficient to indicate that the potential of off-shore drilling cannot realistically be ignored as a significant source for future gas supplies. It is noted, in this connection, that Phillips itself is heavily engaged in off-shore exploration; that it "has been operating extensively off-shore", and has "large uncommitted reserves" in the off-shore area. (93: 12,500, 12,502, 12,546-47)[187]

(2) *The Possibility of Future Imports from Canadian and Mexican Natural Gas Reserves.* Dr. Kahn referred to

[186] 118: 15,885.

[187] In spite of this, Phillips itself makes no reference whatsoever to the subject of off-shore drilling in either of its briefs filed in the instant proceeding.

the possibility that imported gas from geographically adjacent countries (i.e., Canada and Mexico) might become increasingly available in future years to meet projected needs. (102: 13,451; 115: 15,454-56) Such possibilities, of course, are completely in the realm of speculation at this time. With respect to Canadian reserves it is indicated that, at this initial stage of development, the volumes of natural gas available for export may be limited. However, it would be totally unrealistic to overlook the Canadian reserves as a possible source at some future period.

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The pessimistic assumptions presented by Phillips witness Turner may also be balanced by a consideration of certain other statistics of a more encouraging nature. For example, the number of exploratory wells drilled annually by the industry has almost tripled over the past decade. (Exh. 390, Sched. 8) In addition, the total footage of oil and gas wells drilled (including new field wildcats, exploratory, and development drilling) had increased by 152 percent in the period 1945-1956; and even more significantly, with respect to strictly exploratory drilling there was an increase of 221 percent in footage drilled during the same period. (Exh. 390, Sched. 5; 102: 13,455) Finally, it is important to note in this connection that, notwithstanding this rapid increase in exploratory activity, the success ratio for exploratory wells drilled has remained roughly constant during the period from 1946-1956; that, in fact, successful exploratory wells have constituted a noticeably higher percentage of all exploratory wells drilled during that period than in the immediate pre-war years. (Exh. 390, Sched. 8, Col. 3) In this connection Dr. Kahn, referring to the rise in the percentage of dry holes encountered in recent decades which has been stressed in some quarters, pointed out that this change has nevertheless been accompanied by a constant success ratio within the exploratory wells category.

He explained that since dry holes understandably occur with greater frequency in the case of *exploratory* wells than in connection with developmental wells, and since *exploratory* wells have been constituting an increasing proportion of all wells drilled, it is quite understandable that an increasing percentage of dry holes would be encountered during this period; but that this is no cause for alarm in view of the constant success ratio maintained within the exploratory wells category. (102: 13,456-57)

Entirely apart from everything said above with respect to the national gas supply picture, it is of interest to note, in this connection, the following material facts with respect to Phillips' own gas supply picture:

(1) Phillips itself has a 30-year life index, far above the national level. (88: 11,896; 102: 13,454; Exh. 286)

(2) Phillips witness Tarner testified that Phillips "has built up. . . . a tremendous reserve of gas". (65: 9011-12; 66: 9171-72)

(3) The Phillips policy witness, Stanley Learned, testified:

> "As we spend more money for exploration I feel sure we are going to get large reserves of both oil and gas . . .". (93: 12,530)
>
> • • • • •
>
> "We have had pretty good results the first quarter of 1957. You can't take this finding of reserves of oil and gas on any short-term basis, because it is kind of like a card game. You have a series

> of luck, with all the science you put in it, you still have to do a bit of it by luck." (93: 12,531)

(4) In addition, it is relevant to note, in this connection, the following statement made on the record by Phillips' counsel:

> ". . . . I wish you would go back and read my opening statement and the statements in the testimony of Mr. Tarner and Mr. Turner in which we all flatly stated that we were not predicting doom for the gas industry or a shortage of gas." (102:13,487, lines 18-22)

In addition to the matters outlined above, Phillips suggests (initial brief pp. 19-22) that the requirements of consumers, distributors and pipeline companies for supplies of natural gas can presently be met only out of production from wells, to any significant degree, and from no other source; that motorists and other users of oil products, on the contrary, have many potential sources of supply, such as the possibilities for development of reserves of shale, and imports of crude oil. The Phillips presentation on this point is undoubtedly designed to rebut the argument that, because of their general petroleum product requirements, producers will in any event continue to search for oil; that in the course of this search for oil new gas reserves will continue to be discovered, regardless of the prices fixed for natural gas. If there is any suggestion here that such possible alternative sources for crude oil may ultimately result in exploration for and production of crude oil from wells being significantly cut down or abandoned, with a resultant loss of such operations as a source of supply for natural gas, any such implication is here rejected as being completely speculative and remote. The fact is that the economic, engineering and other factors which would be required to produce such a situation certainly are not present at this time, and the possibility is too remote to be given any weight whatsoever in our present determinations.

(31592)

With respect to the suggestion made by Phillips witnesses that a gradually increasing percentage of total domestic oil requirements have been met by oil imports since 1948, Dr. Kahn pointed to the consistent policy of the United States government to hold imports within reasonable bounds. He noted that a Cabinet Committee in 1955 recommended that imports of crude oil be held to their 1954 relationship to domestic production, being a ratio of 10.34 percent, and that a roughly similar ratio was again recommended in 1957. He also pointed out that under the Cabinet Committee formula of 1957, Phillips itself was required to hold its oil imports down to 12,000 barrels per day; that, by way of comparison, its average net crude oil production in 1956 was approximately 150,000 barrels per day; and its average refinery through-put of crude oil was almost 245,000 barrels per day. Under these conditions, it seems reasonable to assume that the import possibilities and their impact on Phillips' domestic exploratory activities will be relatively minor. (102: 13,468-71)

31593

B. *Increasing Depth of Drilling, Accompanied by Increasing Costs.*

Phillips contends that it is faced with the necessity of drilling to constantly increasing depths in order to find and develop new reserves. In this connection, it is contended that since Colonel Drake's well was drilled in 1859 to a depth of 69½ feet, drilling has gone deeper and deeper until the industry is now drilling wells more than 20,000 feet deep, or four miles down; that the annual number of wells

[187a] In this connection, it is relevant to take official notice of the fact that by Presidential Proclamation No. 3279, issued on March 10, 1959, mandatory restrictions were imposed on the importation of petroleum and petroleum products into the United States.

drilled below 12,000 feet had risen to 1,200 wells in 1956, compared with 145 such wells in 1948; that the number drilled below 15,000 feet had risen to 142 wells by 1956.

It is noted, however, that the really significant data to be considered in connection with this problem is the *average* well depth, and here we see a rather different picture. Dr. Kahn's Exh. 390B indicates that the average well depth of "all new wells" was 4,041 feet in 1956, and that the average depth for "all exploratory wells" was 4,574 feet. The average depth for all exploratory wells drilled from 1938-1955 increased only 1,272 feet. Phillips argues that the average well depth figures relating to "all new wells" in Exh. 390B, Col. 1, obscure the fact that numerous shadow wells are drilled each year in "old stripper oil areas", and in secondary recovery operations, which reduce the national average depth but which furnish no gas for the consumer. However, this argument becomes unimpressive when it is noted that the "all exploratory wells" category, set forth in Col. 2, which does *not* include the shallow wells drilled in old stripper oil areas, presents a picture quite similar to the Col. 1 data.

Entirely apart from the above, it is important to bear in mind here that whatever high level of costs had actually been reached in the test year 1954, reflecting the depth of drilling then encountered by Phillips itself, is actually accounted for in our instant 1954 test year cost of service. In addition, the 1956 cost-of-service study introduced by Phillips (Exh. 303), already referred to at an earlier point in this decision, reflects the more recent 1956 exploration and production costs, including any further cost increases which may have taken place by that time as a result of any continuing trend toward deeper and deeper drilling. It is significant that, despite the instant Phillips contention, the total deficiency shown on Exh. 303 for the 1956 cost-of-service study is not substantially higher than that shown on Phillips' 1954 test year cost of service. (Exh. 282)

The only other possible significance of the depth-of-drilling data presented by Phillips would be to support a contention that its exploration and production costs are in a continually rising trend; that accordingly both the 1954 test year costs and the 1956 cost-of-service study are already out of date, and no longer reflect what Phillips needs in order to provide an incentive for continued exploration.

However, this suggestion is not persuasive in view of the Exh. 390B data indicating that the increase in average depth for "all new wells" since 1938 has amounted to only 54 feet per year, whereas the increase in average depth of "all exploratory wells" from 1938 to 1956 has been only 63.8 feet per year. These figures would not seem to indicate a very sharply rising trend for the increase in average depth of wells drilled. Of course, if it should develop in some future year, as a result of this trend and any other cost changes, that the 1954 test year relationship of operating costs, plant and volume of sales was no longer representative, any necessary and appropriate rate adjustments could then be made as the result of a new rate proceeding.

Phillips further stresses, in this same connection, that 31 percent of the nation's marketed natural gas production is now being produced from gas condensate wells and that the average depth of such wells drilled nationally in 1956 was 9,300 feet; that 26 percent of the marketed natural gas production currently consists of casinghead gas obtained from oil wells, and that the average depth of such wells is 6,200 feet. (Phillips initial brief, pp. 31-32) However, this data may be viewed in better perspective when it is recognized that the *average* depth for "all exploratory wells" in 1956 had risen only to 4,574 feet (Exh. 390B), in spite of the fact that this figure includes and reflects all of the exploratory *condensate well* producers and all of the exploratory *oil well* producers which were drilled in that year,

thus giving full weight to the more significant role played by the gas condensate wells and oil wells by that time.

No question is raised here as to Phillips' basic premise that, all other factors remaining equal, deeper drilling is more costly than shallow drilling—nor is it denied that inflation has had an effect upon drilling costs. However, it is relevant to note here that Phillips did not present any figures showing total over-all increases in its own drilling costs due to deeper drilling, or even total over-all nationwide increases. Instead, it merely presented Exh. 233 to demonstrate that

> "The cost of drilling one additional foot at a depth of 10,000 or 15,000 feet is many times the cost of drilling one additional foot at 1,000 feet." (initial brief, p. 25)

The significance of this observation becomes much less serious when it is recognized, as already noted above, that although a much larger number of wells are currently drilled at deeper depths than in earlier years, nevertheless the average depth of "all exploratory wells" drilled in 1956 had still not risen above 4,574 feet.

In addition, it is conceded that *decreases* in cost due to technological progress have provided a partially offsetting factor. Thus, Dr. Kahn noted that the average total cost per foot of oil wells drilled in 1956 amounted to $13.75 per foot, as compared with a 1950 cost of $11.00 per foot. (Exh. 390, Sched. 13, Col. 5) However, he testified

that if these costs were adjusted for changes in the value of the dollar, retaining only that portion of the cost increase attributable to the increased cost of deeper drilling, it would be found that the real cost of drilling wells had declined, not risen, during this time period. He concluded that this was the result of "striking technological progress" of recent years. (102: 13,460-61)

In addition, although increased drilling costs are not to be ignored, it is also significant to measure drilling costs in relation to the *value* of oil and gas reserves discovered. Here we find that since the end of World War II, although drilling costs per dollar of oil alone discovered rose from 26 cents to 38 cents during the period 1946-1956, drilling costs per dollar of *both oil and gas* discovered rose only from 22 cents to 27 cents in the same period. (Exh. 390, Scheds. 13 and 15)

C. *Increasing Exploratory Costs.*

At pp. 32-34 of its initial brief, Phillips sets forth certain data under the heading of "increasing exploratory costs", comparing its total leasehold costs for 1946 with those for 1955, and making similar comparisons for total geophysical expenditures, Land and Geological Department operating expenses, and dry hole expenses and contributions. However, these figures are only meaningful if considered in connection with the accompanying increases in the volume of reserves added. Total natural gas reserves added rose from 17.7 trillion cubic feet in 1946 to 22 trillion cubic feet in 1955. (Exh. 390, Sched. 1) It is thus apparent that the total increase in over-all exploration costs was not entirely due to the increasing costs of exploration *per se*, but reflects in part the expansion of Phillips' exploration activity during these years, which, of course, resulted in higher reserves, higher production and higher revenues.

D. *Decreasing Discoveries Per Unit of Drilling.*

Phillips presented data indicating that during the past ten years the reserves added per exploratory well drilled have decreased 39 percent for gas and 43 percent for oil; and that the reserves added per million feet of exploratory hole drilled have decreased 48 percent for gas and 51 percent for oil. (initial brief, pp. 35-36) It is pointed out that

in the earlier years relatively large reservoirs were found, at relatively shallow depths; that most of the shallow formations where oil and gas might occur have now already been explored; that accordingly deeper and deeper wells are being drilled, finding reservoirs which are relatively smaller and which contain lesser reserves per total reservoir. (57: 7934; 70: 9680) However although it is true, as indicated by Phillips witnesses, that deeper drilling is currently required if reserves are to keep pace with demand, the fact is that such deeper drilling *has* been taking place and that reserves in fact have kept pace with demand. As set forth in detail at an earlier point, increasingly

greater amounts of new gas reserves have been discovered in recent years, culminating in 1956 with a peak of 24.8 trillion cubic feet. (Exh. 390, Sched. 1) As already noted, the record here presented provides no basis for doubting that the industry will be able to achieve the necessary rate of discovery required in the years to come to meet the expanding needs of the market. It is true, of course, that the deeper drilling required for this purpose will be more costly. However, it is worth repeating again that the 1956 cost-of-service study here presented by Phillips demonstrates that whatever higher levels of drilling cost had been reached by that year were apparently counterbalanced by other factors—since the 1956 cost-of-service study showed an over-all deficiency not strikingly higher than that shown in Phillips' test year cost of service.

E. *Increasing Investment and Declining Earnings.*

Phillips presented Exh. 237 to demonstrate that its net investment per million Btu of both gas and oil sold increased from 25.5 cents in 1946 to 56.9 cents in 1956; and Exh. 261 to demonstrate that its earnings (before taxes) on net investment in its total oil and gas production, gas

gathering and gas processing facilities declined from 29.5 percent in 1948 to 8.3 percent in 1956.

The important thing to bear in mind with respect to the data set forth in Exhs. 237 and 261 is that it represents combined oil and gas data. If such combined oil and gas statistics were used as the justification for allocating to natural gas a higher proportion of total exploration costs than justified by the role it plays in the relative results achieved from joint exploration activity, the result would be to impose upon natural gas alone the burden of carrying the entire oil and gas data trend referred to above. It is concluded that the amount of *jurisdictional* revenue which Phillips reasonably requires is governed by the cost-of-service here determined upon the basis of the detailed considerations already set forth in this decision; and that data indicating that Phillips' ratio of net earnings to net investment for its *combined oil and gas production* has declined from a higher figure in 1948 to a lower figure in 1956, does not of itself provide the basis for any cost of service determination in this proceeding.

F. *The Phillips Contention That Increasing Gas-Oil Ratios are Encountered With Increasing Depth.*

A great deal of time was devoted during the hearing to evidence presented by Phillips in support of its thesis that increasing gas-oil ratios are encountered with increasing depths, and to rebuttal evidence presented by interveners Pacific and Eastern for the purpose of controverting this theory. The Phillips theory is: (1) that deeper reservoirs contain a higher percentage of gas and a lower percentage of oil than shallower reservoirs—*i.e.*, a higher initial gas-liquid ratio;

(2) that the deeper reservoirs, with such higher initial gas-liquid ratios, will produce less of the oil in place than reser-

voirs with lower gas-liquid ratios—*i.e.*, the deeper reservoirs have lower oil recovery factors. (Phillips initial brief, pp. 26-30)

The Phillips presentation on this subject was designed to establish that gas is no longer a "junior partner"; that it therefore can no longer properly be contended that the producers' motivation is really to search for oil, that any discoveries of gas are only incidental to that search, and that accordingly oil should bear the major part of the burden of exploration costs. This presentation is also designed to indicate that Phillips is increasingly dependent upon its income from natural gas; that accordingly it is neither practical nor fair to expect oil to carry the burden of increasing costs. The Phillips thesis in this connection is succinctly stated as follows:

> "gas, which has heretofore had a free ride on the search for oil, must now bear its fair share of the cost of the search." (Phillips reply brief, p. 27)

It will be observed, however, that this entire argument constitutes a meaningless "straw man", unless made in the context of an assumption that the methods here adopted for the allocation of exploration costs between oil and gas are in fact motivated by an objective to load upon oil those costs which properly and fairly should be borne by gas. It is concluded that no such assumption is valid, since there is here allocated to gas all that portion of total exploration costs properly assignable to that product, based upon the application of the RAR method—which fully reflects the increasingly important role of gas, relative to oil. As already noted in detail at an earlier point in this decision, the inherent nature of the RAR allocation method is such that it fully reflects and gives full weight to any changes which may occur in the relative volumes of both gas and oil reserves added through exploration, whether as the result of changes in the gas-oil ratios or through any other causes. If this

relationship, as reflected in the test year data, should later become unrepresentative, Phillips would have the opportunity in a future rate proceeding to present evidence indicating a change in the relative volumes of oil and gas reserves added, and a new RAR ratio would then be arrived at, resulting in the allocation of a different percentage of exploratory costs to gas. (102: 13,467) In addition, it should be noted that under the RAR method natural gas reserves are valued at the 1956 *new* contracts price of 13.47 cents per Mcf—a valuation which does not reflect, and is not tainted with the impact of the old, long-term, low-priced contracts, executed at a time when gas truly was still a "junior partner".

Another possible implication to be drawn from the Phillips contention with respect to increasing gas-oil ratios is that it is designed to indicate that an increasingly greater proportion of total hydrocarbons discovered consists of natural gas; that accordingly there is

no longer any justification for the argument that much the bigger share of the producer's total hydrocarbon income comes from oil, and that the price of oil is accordingly a more important factor than the price of gas in influencing the determination by major producers as to where and how much to drill.

If we accepted, for the purpose of this discussion, the Phillips theory that higher gas-oil ratios are encountered with increasing depth, this would merely indicate that in the case of *associated gas wells*,[188] as we drill deeper, gas produced by such wells will represent a greater *percentage* of the total hydrocarbon recovery than it does in the shallower associated gas wells. However, the really significant fact to bear in mind here is that it will nevertheless still be

[188] Gas condensate wells and oil wells producing casinghead gas.

true that the total oil revenue from such associated gas wells will represent the major part of the total hydrocarbon revenue from such wells. The record indicates that Phillips' oil revenue from joint product leases for the year 1954 was $87,245,481, whereas its natural gas revenue from joint product leases was only $13,515,089. (Exh. 353, p. 4, Col. 2; Exh. 304, line 2) It thus appears that in 1954 oil accounted for 86.58 percent of the total hydrocarbon revenue from Phillips' associated gas wells, while gas accounted for only 13.42 percent of the combined revenue. It accordingly seems clear that regardless of the validity of the Phillips theory with respect to increasing gas-oil ratios, the price of oil will still be of greater interest than the price of gas in connection with associated gas wells. Furthermore, Phillips itself has stressed the fact that more and more of our marketed natural gas production is coming from associated gas wells, rather than from dry gas wells—*i.e.*, 57 percent from associated gas wells, and only 43 percent from dry gas wells in 1955. (Phillips initial brief, p. 31) Under these circumstances it would seem clear, as contended by Dr. Kahn,[189] that the price of oil will remain a more important factor than the price of gas in influencing the determination by major producers as to where and how much to drill.

For the reasons set forth above, it is concluded that no purpose would be served by attempting to resolve here the seriously contested issue as to whether increasing gas-oil ratios are in fact encountered with increasing depth. As noted above, the interveners and the Staff hotly disputed this Phillips theory. Eastern disputes the broad Phillips premise that higher initial gas-liquid ratios are encountered in deeper reservoirs, contending that the evidence presented by Phillips on this point is applicable only to saturated reservoirs. Both Eastern and Pacific dispute the Phillips

[189] 102; 13,484; Eastern initial brief, p. 16.

position that deeper reservoirs have lower oil recovery factors.

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They contend that the position taken by Phillips witness Tarner on this subject is unsound because it considered only the effect of shrinkage; that there are other factors which must be considered and which have a greater influence upon the recovery factor than shrinkage, the principal one being the mobility of the oil; that lower viscosity increases the mobility of the oil; that viscosity decreases with depth; that accordingly the increased mobility of the oil in deeper reservoirs more than offsets the effect of shrinkage. (Phillips initial brief, Appendix A4—A11; Exh. 371; Pacific reply brief, p. 204; Staff initial brief, pp. 51-54) This issue has resolved itself into a battle of experts which consumed much time in the open hearing and in the briefs filed by the parties herein. It involves a highly technical question, which it is difficult to resolve with any satisfaction on the instant record. Since it has already been concluded, as set forth in detail above, that the answer to this technical and disputed question would not only any event justify any change in the cost-of-service determinations reached in this decision, the matter does not merit further discussion.

G. *General Conclusions With Respect To The Phillips Presentation On Problems Of Demand, Supply And Increasing Costs.*

It will be helpful at this point to back away from the precise, detailed analysis of the Phillips data presented on these related subjects, and to consider in more general terms the appropriate place and significance of such data in connection with the problem of determining just and reasonable rates in the instant proceeding. Our objective in developing the instant cost-of-service is to allow and reflect Phillips' total jurisdictional costs of all kinds at the

level which they had reached during the 1954 test year, as adjusted for appropriate "known changes". The year 1954 has here been adopted as the test year on the theory that the ratio between Phillips' operating expenses, plant and volume of sales during that year, as so adjusted, was in fact fairly representative of the ratio which will pertain for the ensuing years. However, if it is to be contended that the Phillips level of drilling and exploration costs has so risen since that time that the level of such new costs, considered in connection with the more recent levels of other operating costs and the more recent levels of plant and volume of sales, have established a new plateau, and that the 1954 test year is accordingly no longer representative, then the logic of the situation would require the adoption of a more recent test year in this proceeding.

On the contrary, however, no contention is here made by Phillips that the case should be presented on the basis of a different and more recent test year. Instead, we find that the data presented by Phillips with respect to increasing drilling costs does not in any way purport to represent a comprehensive study of precise total increased costs incurred by Phillips itself, but rather that it takes merely the form of nationwide trend statistics for the entire petroleum industry. Furthermore, with respect to Phillips' own costs we find that the more recent 1956

cost-of-service study presented by Phillips itself shows an over-all deficiency which was not significantly higher than that derived in Phillips' 1954 test year cost of service.

Under these circumstances, although the various types of nationwide trend statistics presented by Phillips on these subjects are of general interest, as indicating changes which have been and are taking place in the petroleum industry, this data does not justify or require a change in any of the

basic cost-of-service determinations made herein with respect to the Phillips cost of service.

On this entire subject, Phillips has here painted a dark and pessimistic picture, implying that the gas supply situation is critical; that accordingly we must develop extraordinary new incentives by shifting the bulk of the exploratory burden to the natural gas consumers; that unless this is done, it will not be possible to achieve the "enormous" rates of increase in the discovery of additional natural gas reserves which allegedly will be required to meet future demands. On the other hand, some of the other parties to the instant proceeding suggest that there is really no great problem at all. It is concluded that the more accurate and objective conclusion to be drawn from this entire presentation is that it is of the utmost importance that there be continued exploration for and discoveries of additional gas supplies on the levels required by our increasing demands. This was recognized by Dr. Kahn when he stated:

> "The ratio of reserves to current production certainly bears watching." (102: 13,445, lines 22-23)
>
> • • • • •
>
> "At no point in my testimony did I attempt, either explicitly or by indirection, to under-emphasize the importance of continuing exploration." (118: 15,882, lines 9-11)

However, the record nevertheless would seem to support Dr. Kahn's conclusion that

> "there is certainly no evidence as yet of a threat presently or in the immediate future of inadequate supplies of natural gas." (102: 13,485, lines 3-5)

This conclusion was supported by the following statement made in open hearing by Phillips' counsel:

". . . I wish you would go back and read my opening statement and the statements in the testimony of Mr. Tarner and Mr. Turner in which we all flatly stated that we were not predicting doom for the gas industry or a shortage of gas." (102: 13,487, lines 18-22)

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There is no basis for here concluding that "extraordinary new incentives" are required to produce the necessary levels of exploration and discovery. It is instead concluded that these required levels can reasonably be met if Phillips is here allowed rates for its jurisdictional gas sales which fairly reflect all of its actual jurisdictional costs, including a reasonable and realistic share of its total exploration costs, plus a reasonable and fair rate of return.

Furthermore, the record does not furnish any basis for assuming that significantly higher levels of additions to our present natural gas supply would result from the allowance of jurisdictional natural gas rates exceeding the above standard. The fact is that price itself is not the sole determinant of the level of exploratory effort. In 1955 almost 50 percent of the sales of natural gas to interstate pipelines were made by twenty major integrated oil companies. This means that a very substantial portion of the nation-wide gas supply comes from integrated oil companies, a major portion of whose total revenues are obtained from the marketing of petroleum products. With respect to these companies, the fact of their integration itself gives rise to a special incentive to engage in their own exploration, and to encourage others to explore by the providing of various inducements. These integrated companies have a stake in controlling the sources of the crude oil which they process, in order to protect their enormous investments and commitments in transportation, refining and marketing. (102: 13,481-82)

(31601)

Furthermore, even if it were assumed that price was a major determinant of the level of exploratory effort, the impact of the price of gas alone would inevitably be far less influential than the price of oil, for the reasons already pointed out in detail above. Accordingly, although the increasing demand for and the increasing price of gas in recent years has undoubtedly increased the contribution of gas to aggregate exploratory incentives and funds, *it is still unrealistic to regard the search for gas as an independent or preponderant factor in total exploratory activity.*

Finally, predictions have been made as to the existence of reserves of natural gas still to be discovered in the United States, in the order of approximately one trillion Mcf.[190] The extent of such remaining supplies of natural gas, still awaiting discovery, is fixed ultimately by nature, and not by the price of gas or oil. The gas is there beneath the surface, and its total physical volume cannot be altered or influenced by the price of gas today or in the future. In addition, although the rate and dollar pattern of its discovery will be influenced to some extent by price considerations, the price of oil will undoubtedly play a more important role in such influence than the price of gas. (102: 13,486)

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XX. Phillips' Contention Re Alleged Negligible Impact of Its Recommended Rates

Phillips contends that the rate increases proposed by it in this proceeding would have only a negligible impact, because (1) such increases can easily be totally absorbed by its pipeline customers; and (2) even if this were not the case, the resultant gas prices to be paid by the consumers would still be competitive with other fuels.

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190 See reference by Dr. Kahn to estimates by Terry and Winger of the Chase Manhattan Bank. (102: 13,486)

In support of the first contention, Phillips presented witness Wilhelmi [191] to demonstrate that the continuing depreciation accruals of the pipelines and distribution companies "offer a means for possible absorption of much of the increasing cost of exploration and development". (Phillips initial brief, p. 170) Wilhelmi testified that so long as the pipeline and distribution companies can obtain a constant gas supply, they will have a decreasing cost of service as the result of an increasing depreciation reserve, which under normal operations does not have to be plowed back into the business merely to continue adequate gas deliveries to existing customers; that the amount of this reserve is deducted from the original property investment, so that on a constant volume of gas handled the accrual of the reserve operates to reduce the net investment, thus producing a lower rate base and a lower return component; that the force of depreciation accruals, operating in this manner, "may offset a part, or possibly all of increasing costs of production, so that they may never reach gas consumers." (58: 8155-57) In order to demonstrate this thesis, Wilhelmi presented Exhibit 262 to show

> ". . . how depreciation reserve accruals continually work to reduce the net plant account, and, therefore, the cost of service of natural gas pipeline companies and gas distribution companies.
>
> "It also shows the possible magnitude of those cost reductions, and that they work to keep the price of gas to the consumer down, although gas production costs are going up, so that gas will not necessarily either be priced out of its present markets or make obsolete the

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191 Engaged in various phases of the natural gas business for 35 years, including a period as consultant on the staff of Ebasco Services, Inc., of New York City. Presently engaged in private consulting practice in Shreveport, Louisiana.

gas appliances and equipment of 27 million natural gas users." (58: 8158, lines 2-11)

However, in the course of interrogation by the Presiding Examiner, Wilhelmi later agreed that the conclusions set forth in Exhibit 262 were valid only on the assumption that the pipeline or distribution company's other operating expenses would remain constant during such years, that its utility plant would not be expanded, and that the only problem encountered would be that of increases in purchased gas cost. (58: 8174, line 19; 8175, line 9) The following colloquy then ensued:

"PRESIDING EXAMINER: Is it your contention that the hypothetical assumptions, which are the basis for your exhibit, are realistic assumptions which will obtain in the future?

"THE WITNESS: As I said a moment ago, they may not be realistic assumptions. Operating costs may go down, or they may go up, but in order to find the force of the depreciation accruals, that is what I had to do. That is the only way you could actually compute it and find it.

"PRESIDING EXAMINER: Well, do you go any further, then, with your Exhibit 262, than to indicate to the Commission that if all of those assumptions should obtain in the future years, that the pipeline company then would be able to absorb a purchased gas cost increase without getting an increase in its own rates, but based on those assumptions, that the other costs will remain static?

"THE WITNESS: I don't believe I understand what you mean—Do I go any further than that?

"PRESIDING EXAMINER: You do not—do you take

the position that Exhibit 262 bears any other significance than that as I have just summarized it?
"THE WITNESS: No." (58: 8,175, line 12—8,176, line 8)

Wilhelmi made it clear that these assumptions are *not* realistic, in his responses to later interrogation, as follows:

"Q. Based on your experience as an executive of or consultant for natural gas distribution facilities, can you state what has been the trend of costs of operation, excluding the cost of purchased gas for such operations?

* * * * *

"Q. But the general trend of costs, other than costs of purchased gas, have been up?
"A. The total costs of operations have been upwards.

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"Q. Would not the same cost conditions apply to pipeline operations?

"A. Again, the total cost of operations have been upward. . . ." (92: 12,352, line 22—12,353, line 20)

In the light of current conditions, it certainly is not unreasonable to expect that the operating costs of pipeline companies and distributors may show a net increase in the future, and that their net investment may also show an increase as the result of plant expansion, required to satisfy the increasing market demands estimated by Phillips witness Turner. It is obvious that the magnitude of the rate increases which might be required under such circumstances would clearly be affected by the level of the purchased gas costs which the pipeline companies may be required to pay to their producer-suppliers.

In view of the matters noted above, this particular Phillips contention is not entitled to further serious consideration.

The second type of "impact" presentation made by Phillips consisted of Wilhelmi's Exh. 292, headed "Computation of the Effect of Phillips' Proposed Rate Increases on the Average Prices of Gas if Such Increases Must be Passed on to the Consumer". The purpose of this presentation was to demonstrate that the impact of the rate increases here proposed by Phillips, even if accompanied by similar rate increases to the instant pipeline interveners from other producer-suppliers, would still leave gas competitive with other fuels, and that the resultant purchased gas cost increases would still be within the ability of the pipelines and distributors to recover from their customers. (Phillips initial brief, pp. 170-171) Actually, the Exh. 292 computations are subject to the same defects as those already indicated with respect to Wilhelmi's Exh. 262 presentation. They are of interest only in connection with the entirely unrealistic assumption that other cost factors encountered by the pipeline and distribution companies would in the meantime remain static, so that they would be confronted with no problem except that of increases in purchased gas cost.

Furthermore, the Wilhelmi study is regarded as too speculative and incomplete to be of any real value, for certain additional reasons set forth below. It did not give adequate consideration and effect to the impact of Phillips' proposed rates upon *industrial sales*. This is a vital consideration because when natural gas becomes noncompetitive with other fuels, the inevitable consequence is that the industrial load is reduced, or is lost. This, in turn, reduces the load factor, with the final result that there is an increase in unit cost for the remaining gas transported and sold—*i.e.*, in the rates for residential and house heating uses. When Wilhelmi was asked during cross-examination whether he had made any study as to the impact of the proposed Phillips rate in-

creases upon industrial gas sales in the state of Wisconsin, he replied as follows:

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"A. No specific study, other than to compare the gas prices presently and those that would result with the prices of oil as reported by Platt's Oilgram for Milwaukee, and also the prices of coal that it seemed were being paid up there by the power plants in that area which I believe were probably the lowest anybody buys coal for.

"Q. In other words, you don't know the impact on industrial sales of these rates?

"A. No, there was no public record that I could find of any specific industrial customers that I could use for a basis for making such a study." (92: 12,346, line 23—12,347, line 8)

However, intervener's witness George B. Johnson, Vice-President in Charge of Operations, Minneapolis Gas Company [192], testified that a comparison of gas prices, for this purpose, with the prices of oil as reported by Platt's Oilgram was meaningless, because:

"In determining the loss of interruptible sales, the cost of competitive fuels for industrial uses is extremely difficult to obtain. While the cost of competitive fuels for residential uses may be found in statistical services such as the Bureau of Labor Statistics and Platt's Oilgram Service, as was done by Mr. Wilhelmi, such is not the case with industrial fuels.

"Competitive fuels for large industrial users are generally priced on an individual basis from the supplier to the customer. These bids are usually confidential

[192] A distribution company customer of intervener Northern Natural Gas Company.

and extremely difficult to obtain specific information on. Also one price will exist for a fuel for standby uses and another lower price if the customer will burn the fuel on a 100 percent basis." (100: 13,116, lines 4-17)

The importance of giving proper weight to the impact of Phillips' proposed rate increases upon *industrial* sales was demonstrated by witness Johnson as follows:

"Northern sells a substantial amount of interruptible gas, amounting to about 49 percent of its total sales on an Mcf basis in 1956. Any increase ordered by the Commission to be placed on the commodity rate could well result in the loss of large volumes of interruptible sales on Northern's system. A substantial loss of these sales would greatly affect Northern's unit costs and add to the financial impact on the ultimate consumer.

"In calculating the loss of interruptible sales, it would be necessary to first consider the loss of Northern's direct sales and those of its utility customers. This loss would then be spread over the remaining sales and would result in an increase in the city gate rates.

"Secondly, the loss of revenue to the distribution companies as a result of dropping their own interruptible sales would then have to be considered. Any such losses would have to be recouped by an increase in the distributor's rates." (100: 13,115, lines 5-22)

Wilhelmi himself expressed the same view, as follows:

"The problem that I was trying to present at that particular point in my testimony was that in this area, where gas is being distributed by Northern Natural Gas Company, there might be a substantial impact on the consumer, particularly the residential consumer and

the domestic, or rather the commercial consumer of Phillips' rate increases, because of the fact that Northern Natural Gas Company has a very large interruptible gas load. They have not developed any storage facilities, as far as I know, on their system. Consequently, even with the interruptible gas load that they have, their sales in the summertime are substantially smaller than they are in the winter, and the increases by Phillips, their gas prices, would have an impact on the commodity costs of the gas by Northern which would affect the prices of gas sold to their interruptible customers."

* * * * *

"I also pointed out that some of those interruptible customers were certainly customers of the distribution companies, and it would take a very substantial study to ascertain what all those factors were." (92: 12,350, line 5—12,351, line 3)

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Along the same lines, Wilhelmi also testified:

". . . I tried to get that across, but I missed it, that there is going to be an additional impact on the residential and commercial and industrial gas cost brought about by any loss of interruptible gas business that these distributors may have themselves over and above that that I have been able to estimate I think fairly accurately from the data at hand.
"*I can't do anything with that second range of loss.*" (63: 8864, lines 12-19; emphasis supplied)

It is finally noted that Wilhelmi's Exh. 292 study also fails to reflect in any way certain other possible impact factors, such as:

(1) The effect which a reduction in interruptible load might have upon Northern Natural in view of the increasing amounts of gas which it purchases under "take or pay" contracts. If Northern's requirements, as a result of any such reduction in interruptible sales, should fall below the minimum take provisions of these contracts, the cost of gas paid for by Northern, but not taken, would result in additional unit costs which would have to be spread over its remaining sales. (100: 13,116)

(2) The fact that the ultimate financial impact of such producer rate increases upon distribution companies would vary according to the manner in which purchased gas cost increases to the instant pipeline interveners were subsequently distributed, as between demand rates and commodity rates fixed for the pipeline. To the extent that any such increases were ultimately reflected in the pipeline's *demand* rates, the resultant impact upon its distribution company customers would vary depending upon the latter's load factor. (100: 13,114)

Furthermore, in the exercise of its responsibility to carry out the primary aim of the Natural Gas Act "to protect consumers against exploitation at the hands of natural gas companies",[193] the Commission is concerned with far broader considerations than the impact of the instant decision upon Phillips' own customers. This Commission must consider and weigh the much broader impact which the positions it may here adopt on the major issues in this case (*i.e.*, the allocation of exploration costs between oil and gas, the claimed phantom tax allowance, the rate of return to be allowed, *etc.*) will have upon the over-all regulation of independent producer rates in general—and the resulting ultimate impact of such determinations upon consumers in general.

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[193] *F.P.C.* v. *Hope Natural Gas Co.*, 320 U. S. at 610; *City of Detroit* case, *supra*.

Contemporary history shows that pipeline and distribution companies are being confronted with significant cost increases in many areas, including purchased gas costs; that the cumulative effect of all these factors has been a continually increasing trend of higher prices to the ultimate consumer—with the result that distribution companies in some areas fear that they are already "being priced out of the market", while in other areas this situation appears to be coming closer. There can, of course, be no doubt that the continually rising trend of purchased gas costs represents one of the significant factors which combine to produce this cumulative impact, and it is, therefore, concluded that it is totally unrealistic to consider the potential impact of the Phillips rate proposals in the instant case upon the narrow and artificial basis here suggested by Phillips.

XXI. THE FIELD PRICE PRESENTATIONS IN THIS PROCEEDING

As already noted above, Phillips here takes the position that its jurisdictional rates should be determined upon the basis of its overall *cost of service*. This was made perfectly clear by its policy witness, Stanley Learned, in the following colloquy:

> "Q. Do you wish to have the Power Commission fix your prices by value as you have defined it?
> "A. No.
> "Q. You do want to have it fixed according to a cost of service?
> "A. Yes, sir." (92: 12,481, lines 10-15)[194]

[194] On the basis of its claimed cost of service in this proceeding, Phillips recommends proposed rates ranging from a high of 22.75 cents per Mcf to a low of 16.5 cents per Mcf, depending upon delivery conditions. The maximum proposed rate of 22.75 cents per Mcf is, of course, higher than any of the claimed "commodity value" or "field price" levels presented in this proceeding.

However, Phillips explained that in order to meet the eventuality that the Commission might conceivably determine market price, or field price, to be a proper criteria for the establishment of producer rates, it desired to make a field price presentation. (62: 8675) This presentation was made by Phillips witness Mayer, who took the position that the "going market price" for natural gas in the entire Southwest producing region (including Texas, Oklahoma, Kansas, Louisiana, Arkansas, Mississippi and New Mexico) was "at least 21 cents per Mcf" at 14.65 p.s.i.a. (62: 8755-56) He characterized this 21-cent price as "being representative of prices paid for 1,000-pound, gathered, sweet, dehydrated gas".

He then applied to this 21-cent figure certain price differentials based upon varying delivery conditions and quality.[195] On the basis of these differentials he developed prices for each and every Phillips jurisdictional contract, ranging from a maximum of 21 cents to a minimum of 14.75 cents per Mcf. (Exh. 291; 63: 8770) This claimed 21-cent "going market price" figure is, of course, somewhat lower than the maximum 22.75-cent rate recommended herein by Phillips on the basis of its system-wide cost of service. It will be noted, however, that the Phillips briefs make no reference to this field price evidence, and that Phillips here bases its recommended rates solely upon its claimed cost of service.

On the other hand, Southern presented *and relies on* a major field price presentation, made through its witness Falck,[196] on the basis of which it is contended that the

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[195] These price differentials for varying delivery conditions will be discussed in detail at a later point.

[196] A private consultant in the electric power and natural gas field. Formerly Director of the Office of War Utilities, War Production Board, and later Director of the Office of Energy and Utilities of the National Security Resources Board.

weighted average field price, or commodity value, in 1956, of natural gas produced in the Permian Basin and Panhandle areas [197] was 9.13 cents per Mcf for the Permian Basin area and 9.68 cents for the Panhandle area. (Southern brief, p. 46) Southern takes the position that the rates proposed by Phillips in its Section 4(e) rate filings in the instant proceeding, for the Permian Basin and Panhandle areas [198], represent increases within the range of these "weighted average field prices", and may, therefore, be supported as just and reasonable rates. However, Southern contends that any rates higher than its claimed weighted average field price levels, even if found not to be in excess of the Phillips cost of service, must here be denied. In taking this position, Southern stresses the following conclusion, expressed by its witness Falck:

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> "It is one thing to use an asserted revenue *deficiency* based upon claimed cost of service to bring a producer's price *up* to the average price in the field; it is quite another to use the asserted revenue deficiency for the purpose of raising a producer's price far beyond the prevailing level of field prices". (99: 13,072, lines 1-6; emphasis supplied)

In view of the conclusion reached in this decision that Phillips' over-all unit cost of service amounts to 11.662 cents per Mcf, a level somewhat higher than Southern's claimed weighted average field prices of 9.13 cents for the Permian Basin area and 9.68 cents for the Panhandle area, it is necessary to deal briefly here with this theory as ex-

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[197] Which constitute the source of a major portion of the natural gas supply for this intervener group.

[198] Running from 6¾ cents-8¾ cents per Mcf for the Permian Basin area, and 11 cents per Mcf in the Panhandle area.

pounded by Southern. That theory, in effect, amounts to a contention that although the doctrine of the *City of Detroit* case, *supra*, requires that the traditional rate base method must be used as a point of departure where the field price levels sought by the producer are *higher* than the determined cost of service rates, nevertheless where such field price levels are *lower* than the determined cost of service rates the lower field price levels should be treated as controlling.

It is concluded that this is an unjustifiable position. It is true that the Court of Appeals in the *City of Detroit* case, *supra*, refused to agree that the field price method could not under any circumstances be used in arriving at "just and reasonable" rates. However, the Court clearly did not hold that the Commission is *compelled* to treat field price levels as controlling for this purpose. The most that can be said about the *City of Detroit* decision in this connection is that it upholds the discretionary power of the Commission to consider field price evidence *as one of the factors* in arriving at its decision, provided that certain important basic requirements laid down by the Court are observed. Any failure in this proceeding to allow Phillips the opportunity to recover rates sufficient to recoup its proper cost of service as here determined, would be inherently unfair and contrary to the public interest. It might also raise a serious question with respect to possible violation of the constitutional prohibition against confiscation.

For reasons which will later appear, it would be helpful and instructive at this point to direct our attention to a brief review of the various types of field price evidence which were presented in this proceeding, as follows:

(1) *The Phillips Field Price Presentation.* Phillips witness Mayer derived his alleged 21-cents per Mcf "going market value" for all Phillips jurisdictional natural gas sales on the basis of five selected, high-priced contracts ne-

gotiated in 1954, 1955 and 1956 in the South Louisiana area—buttressed, after some interrogation by the Presiding Examiner, by a reference to the fact that Natural Gas Pipe Line Company of America, in a proceeding then pending before the Commission, was "proposing to pay 29 cents per Mcf for the delivery of gas of pipeline quality and at pipeline pressures, at Beatrice, Nebraska". (62: 8759, lines 15-20; emphasis supplied) This delivery point was 400 miles from the Texas Panhandle,

which is the center of the Panhandle-Hugoton field. When interrogated further by the Presiding Examiner, Mayer agreed that during the past two or three years contracts have been negotiated between pipelines and producers in the Texas area, for example, at price levels lower than 21 cents per Mcf; that he had, in fact, not examined all of those lower-priced new contracts for the purpose of determining whether they were in fact subject to conditions, which under his own standards, would render them non-representative of true "going market value"; that he accordingly could not say that those lower-priced contracts should not also be considered and given appropriate weight. (63: 8777-8778) Mayer finally summed up his position as follows:

> "Now, the price that is paid for gas may be affected by a great many things, but what I was trying to show was that to at least five different pipelines, gas was worth 21 cents under the conditions of delivery of those five contracts." (63: 8778, lines 12-15)

It is thus obvious that Mayer's 21-cent figure cannot even be regarded as an average of the prices negotiated *in recent years* under newly executed contracts in the areas where Phillips' production occurs.

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An alleged "field price" figure based exclusively on the meager evidence just summarized could not possibly be given serious consideration under any serious field price approach. Since it is here concluded that it has not been established by any persuasive evidence in this record that Mayer's 21-cent per Mcf figure truly represents the "going market price" for natural gas in the Southwest producing region, the suggestion that Phillips' claimed unit cost of service of 22.75 cents per Mcf is really not unrealistic or startling, in that it is quite in line with the alleged "going market price" of 21 cents for natural gas in the entire Southwest, becomes quite meaningless.

By contrast, Eastern's field price witness, Dr. Joskow,[199] made a comprehensive study of all prices paid by interstate pipelines under gas supply contracts newly negotiated in 1954, 1955 and 1956 in the Panhandle-Hugoton, Permian, West Texas, and Gulf Coast areas. This study disclosed that interstate pipelines paid a weighted average price in these areas of 11.11 cents per Mcf for 1954 deliveries under contracts executed in 1954, 12.78 cents for 1955 deliveries under contracts executed in 1955, and 13.47 cents for 1956 deliveries under contracts executed in 1956. (Exh. 387, p. 3, 100: 13,195)

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Finally, as noted above, Southern witness Falck presented a comprehensive study of all prices paid by interstate pipelines in the years 1954, 1955 and 1956 for all purchased gas, without regard to the date of the contract, covering production from the Permian Basin and Panhandle areas. Based on this study Falck arrived at 1956 "weighted average field prices" as follows: (1) for the Permian Basin area, 9.13 cents per Mcf for gasoline plant outlet purchases

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[199] Assistant Professor of Economics at City College of New York, also employed as Research Director of the private consulting firm of Boni, Watkins, Jason and Co., Inc.

(residue gas), and 9.45 cents for wellhead purchases (raw gas); (2) for the Panhandle field, 9.68 cents for gasoline plant outlet purchases, and 10.66 cents for wellhead purchases. (Exhs. 378 and 379)

As earlier noted, it is here concluded that Phillips' unit cost of service amounts to 11.662 cents per Mcf. It has already been concluded above that it would be improper to here deny to Phillips the opportunity to recover its jurisdictional cost of service, as thus determined. At the same time, for reasons which will now be set forth, it has also been concluded that rates in excess of those derived from such unit cost of service are not warranted in this proceeding. Accordingly, no purpose would be served by attempting to determine here what would be an appropriate field price level in the event that rates were here to be fixed on the basis of a field price approach.

As already set forth in detail at an earlier point, it is here concluded: (1) that the required levels of exploration and discovery can and should be met if Phillips is allowed rates for its jurisdictional natural gas sales which fairly reflect all of its actual jurisdictional costs, including a reasonable and realistic share of total exploration costs, plus a reasonable and fair rate of return; and (2) that the instant record does not furnish any basis for assuming that any significantly higher level of additions to our natural gas supply would result from the allowance of jurisdictional natural gas rates exceeding the above standard.

In the *City of Detroit* case, *supra*, the Court of Appeals held that the Commission may, under the Natural Gas Act, give consideration to the need for encouraging exploration and development of gas resources "at least to the extent of allowing recovery of development and exploration *costs*." However, the question as to whether the Commission may properly go further than merely allowing recovery of development and exploration *costs* was left undecided by the Court, because of its conclusion that disposition of the ap-

peal on the record then before it did not require the resolution of that question. (230 F.2d at 817) The court further held that use of the field price method can be justified only in terms of a demonstrated public interest; that the allowance of an amount found necessary to encourage exploration and development of gas resources could actually be included without resort to the field price approach; but that if the field price method were

used for this purpose, the evidence and the findings must show that the increase in rates thus caused (over and beyond the amount calculated under the traditional rate base method) would be no more than reasonably necessary for the purpose of encouraging the required levels of exploration and development.

In view of the basic conclusions reached herein, as outlined above, it is impossible to make the required finding in this proceeding that the difference between the rates herein computed on the cost of service basis, and any higher field price levels, would constitute an amount "reasonably necessary" for the purpose of encouraging the required levels of exploration and development; or that *any amounts* in excess of the rates herein computed are "reasonably necessary" for such purposes.

XXII. SYSTEM-WIDE RATES vs AREA RATES

One of the major problems which must be resolved in connection with the regulation of independent producer rates is the question whether such rates should be fixed on the basis of a system-wide, uniform rate approach, or on the basis of an area-pricing approach.

Phillips here uses a system-wide, uniform rate approach, under which it proposes schedules of uniform rates for all customers, based upon its system-wide cost of service, with

rate differentials to reflect four different delivery condition factors.[200] Under this method Phillips witness Mayer established a top price for gathered, high-pressure, dehydrated and treated gas of 22.75 cents per Mcf. Applying the various differentials to each separate delivery, he derived recommended rates for each contract, with prices varying from the top of 22.75 cents per Mcf to a low of 16.5 cents per Mcf. (Exh. 324)[201]

The Staff and the interveners in this proceeding attack the system-wide rate approach, and advocate instead an area-pricing approach. However, there is a wide area of disagreement between the Staff and th various interveners as to the manner in which an area-pricing approach should be applied. Eastern takes the position that area prices should

be developed on the basis of a system-wide cost of service, and not by constructing a separate cost of service for each Phillips producing area. The Staff and other interveners, however, insist that a separate cost of service must be developed for each producing area. In addition, there are other differences which will shortly be outlined in detail.

A. *The Staff's Area-Pricing Method*

The general problems inherently arising under any area-pricing method based upon a separate cost of service for each area will be discussed somewhat later. At this point attention will be directed to the particular defects in the Staff's method.

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[200] These four rate differential factors were (1) point of delivery, (2) pressure, (3) whether dehydrated or undehydrated, and (4) whether sweet or sour. These factors will be discussed in detail at a later point.

[201] With the exception of certain categories of rate schedules as to which Phillips here recommends that no rates should be fixed. This problem will be discussed at a later point.

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Staff cost of service witness Vaught determined Phillips' costs "on the basis of the six areas that Phillips maintains on its books for the purpose of accounting for the operation of its total over-all properties." (48: 6,902, lines 22-24) He described these as "accounting areas maintained by Phillips in its accounting for costs." (48: 6,903, lines 6-7)[202] Vaught's six "areas" were designated: (1) Hansford, (2) Sherman, (3) Borger, (4) Pampa,[203] (5) Permian Basin, and (6) Miscellaneous. However, Phillips witness Cramer testified that these six different so-called areas were actually not geographical areas at all, but merely accounting summaries maintained in Phillips' Natural Gas Department. The Staff made no attempt itself to obtain any knowledge as to what was actually encompassed in these so-called "areas." Staff witness Munn stated:

> "These were strictly bookkeeping areas that we followed for convenience."
>
> "MR. TORKELSON: They were bookkeeping areas that were used by the company?
>
> "THE WITNESS: By the Company, yes, in setting up their books.
>
> "MR. TORKELSON: Do you know the basis on which the company has set up these various areas?
>
> "THE WITNESS: No." (42:6300, line 22—6301, line 5)[204]

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It was made quite clear that these so-called "areas" have no real geographical significance, in the following testimony by Phillips' witness Cramer:

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[202] Exh. 208.

[203] All in the Panhandle region.

[204] Also see similar statement by Vaught, at 48:6902, lines 8-9, and by Staff witness Crosby, at 55:7729-31.

"These six different so-called areas are not geographical areas. They are merely accounting summaries. For example, the Sherman and Hansford areas, as shown on the statements of Phillips, constitute the gathering systems serving the Sherman and Hansford gasoline plants. These two plants are located side by side, and the geographical areas served by the systems connecting these two plants are in some instances over-lapping.

"What has been referred to as the Permian Basin area constitutes all gathering systems located in the Permian Basin production area of west Texas and New Mexico. There are a number of systems in that area, most of which are widely separated, and not connected with each other.

"However, wellhead sales of gas from leases located in the Permian Basin producing area are included in the miscellaneous summary.

"Q. What else is included in the miscellaneous summary?

"A. That accounting summary includes everything else not included in the other five. It is a combination of gathering systems and wellhead sales. It includes all gathering systems not included in one of the other five accounting summaries, and all wellhead sales except those included in Borger and Pampa summaries.

"Q. In summarizing wellhead sales under Miscellaneous, is any geographical significance given to the location of the wellhead sales?

"A. No. As I stated, this accounting summary includes all wellhead sales except dry gas wellhead sales located in the Borger and Pampa operating areas. For that reason, many of the wellhead sales included under Miscellaneous are located in the same geographical area as system sales included in one of the other accounting summaries. The absence of any geographical significance is shown by the fact that the four accounting

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subdivisions of Hansford, Sherman, Borger and Pampa relate to gas produced and purchased in only nine counties, and the Permian Basin accounting subdivision relates to gathering systems in nine other counties.

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"The Miscellaneous subdivision not only includes everything else in the United States outside these 18 counties, but also includes wellhead sales located within some of these 18 counties." (59: 8,260, line 1—8,261, line 15)

In addition to the matters outlined above, the Staff's use of these accounting summaries maintained in Phillips' Natural Gas Department ignores the fact that Phillips' Oil and Gas Production Department, which has responsibility for all casinghead and condensate gas production in all areas, is organized by districts which do not correspond to these accounting summaries of the Natural Gas Department. This problem did not concern Staff witness Vaught, in view of his technique of determining the unit cost of casinghead and condensate gas by simply imputing to those products the unit cost of producing dry gas in the entire Panhandle-Hugoton field. However, as noted at an earlier point, it resulted in assigning to casinghead and condensate gas the dry gas production costs for the shallow Panhandle and Hugoton fields, representing the lowest dry gas production costs on the Phillips system, and that technique is here rejected as totally unacceptable for the purpose of this proceeding.

The next step in the Staff's area-pricing approach was taken by its rate witness Crosby,[205] in his Exhibits 215 and 215-A. For pricing purposes, Crosby combined witness Vaught's four areas in the Panhandle region (Hansford, Sherman, Borger and Pampa) into one Panhandle area.

[205] A Staff rate engineer, associated with the Commission since 1939.

His second pricing area was the Permian Basin area, and his third was the Miscellaneous area. However, he further subdivided the Miscellaneous area into seven smaller units based upon the operating districts of the Oil and Gas Production Department. Crosby's rationale for grouping the four Panhandle areas for rate purposes was as follows:

> "Because they are contiguous, because gas was exchanged among them, because Mr. Vaught has used the average cost of dry gas for these four areas for imputing cost to casinghead gas, and because Phillips' present prices in some cases transcend the various areas." (45: 6,610, lines 16-20)

It is interesting to note that the Staff (pp. 32-33 of initial brief) attacks the system-wide rate approach as

> "a total disregard of operating conditions within historically known producing areas; a total disregard of the wide difference in costs incurred in producing and selling gas as between areas in Phillips' system. . ."

However, an analysis of the three basic Staff pricing areas (Panhandle, Permian Basin and Miscellaneous), as thus applied by the Staff, discloses that they actually do not truly reflect cost differences between different producing areas at all:

(1) The Panhandle area, as used by the Staff, consists of the average costs of the four areas designated Sherman, Hansford, Borger and Pampa. However, since average costs were used, the only difference in the Staff's recommended rates within these four areas reflects differences in delivery conditions, and not differences in cost. The explanation given by Staff witness Crosby for his combining of these four areas into one group, quoted above, did not

include any contention that costs in all four of these areas were relatively similar.

(2) The average dry gas production cost in these same four areas was also used by the Staff to determine its imputed cost for casinghead and condensate gas produced in all areas, so that admittedly any differences in operating conditions and cost levels as between different areas was completely ignored by the Staff in determining its proposed rates for casinghead and condensate gas.

(3) The only portion of Phillips production included in the Staff's Permian Basin area consists of casinghead and condensate production transferred to the Phillips gathering systems. Since the Staff's imputed dry gas cost was applied to this production, the same average production costs for the Panhandle area, referred to above, are thus also used by the Staff in the Permian Basin area—with differences in gathering costs creating the only difference in recommended rates.

(4) It thus appears that the recommended rates in two of the Staff's three basic areas are derived from the same average production costs, and in effect constitute the same rate for both areas, adjusted only for delivery conditions.

(5) The Staff's third basic area, Miscellaneous, includes both sales of dry gas and sales of casinghead and condensate gas. As to casinghead and condensate gas, the recommended rate is based upon the same imputed cost used in the Panhandle and Permian Basin areas.

In addition, the Staff method created certain other disturbing problems. Under this approach, the Staff derived an average cost of 36.72 cents per Mcf for wellhead sales of dry gas in its Miscellaneous area. Because of Staff recognition that Phillips could not realistically be expected to sell this gas at any such price level, Staff witness Crosby adopted the position of not recommending any rate at all

for these particular sales. (45: 6,612, 6,617; Exh. 215, Sheet 13, footnote 5) At the same time, however, the Staff took the position

that each "area" would have to stand on its own feet; that accordingly any deficiency resulting from such sales in the Miscellaneous area at prices substantially below the 36.72 cent figure could not be made up by a corresponding increase in the rates authorized for sales from other areas, and that Phillips would therefore be "stuck with a loss." (45: 6,621, lines 17-19; 6,619-21) At the same time, although thus requiring Phillips to absorb any such deficiency from these sales in the Miscellaneous area, the Staff position, as advanced at the hearing, would have required the *reduction* of Phillips' current rates for certain types of sales in other areas.

This completely untenable position has now been abandoned in the Staff brief (pp. 144-145 of initial brief), where it is recommended that this problem be resolved as follows. With respect to dry gas sales in the Miscellaneous area, it is now recommended that Phillips should be permitted to charge the highest rate which it was receiving as of July 1, 1956 for any similar sales of gas made in these respective areas. The Staff then recommends that the remaining deficiency should be distributed volume-wise against all of Phillips' sales in other areas. On the basis of the Staff's cost of service, this would require the addition of a further charge of 0.67 cents per Mcf to the rates derived by the Staff for each other area. To this extent, it is of course obvious that the rates finally proposed by the Staff herein for each of its pricing areas would not technically represent true area rates at all.

For the reasons outlined above, it is here concluded that the area-pricing approach presented by the Staff in this proceeding is not acceptable.

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B. *The General Problems Inherent In An Area-Pricing Approach Based Upon a Separate Cost of Service For Each Producing Area*

As already noted above, although the Staff and the interveners attack the system-wide rate approach and advocate the adoption of an area-pricing approach in this proceeding, they differ substantially among themselves as to the manner in which an area-pricing approach should be applied. As a matter of fact, although interveners Southern, Pacific, Wisconsin, El Paso, and Panhandle seem to advocate the adoption of an area-pricing approach based upon a separate cost of service for each of Phillips' producing areas, they have not indicated how such area rates, in their view, should be constructed. As further evidence of the confusion and disagreement between these parties as to how an area-pricing approach should be applied, it is of interest to note the conflicting positions taken by the Staff on the one hand, and the interveners on the other with reference to the manner in which exploration costs should be assigned to the different areas. The Staff allocates exploration costs between its proposed areas on a "volume of production basis"—

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> "by allocating on the basis of the Mcf produced in each area. This method of allocation gives weight to the production in each area." (initial brief, p. 36)

Actually, the Staff thus treats exploration costs on a company-wide basis, instead of allocating such costs to its selected areas on the basis of the incurrence of those costs in each area. This, of course, represents a still further departure on the part of the Staff from a true area-pricing approach, since the volume of production in each area actually has little, if anything, to do with the actual incurrence of exploration costs in such area, or with the relative benefits

received by such area from the exploration activity involved.

On the other hand, the interveners (with the exception of Eastern) argue strenuously that they should not be required to pay the cost of any exploration which will not be of immediate, direct benefit to them. They accordingly contend that customers purchasing Panhandle and Hugoton gas should not be charged with any of the costs of other areas. This attitude was sharply high-lighted in the course of Staff counsel's cross-examination of Southern witness Chapin. Chapin's attention was here directed to the area designated by him as the Rocky Mountain area (Exh. 361). Staff counsel suggested a hypothetical situation in which the exploration costs expended in that area were very high, but the volume of gas currently produced therefrom was relatively small, with the result that Phillips in order to recoup its expenditures for the test year would have had to sell all gas produced from that area at 54 cents per Mcf. Since there would, of course, be no market at that price, the hypothetical question assumed that Phillips would incur a substantial deficiency on such sales. Chapin was then asked whether, under his theory, Phillips should be required to absorb such a deficiency until production and sales from that area had increased to the point where the gas could be sold for a price commensurate with its unit cost. Chapin replied:

> "Well, I would expect Phillips to sell the gas at the best price it could get and that would be approved by the Commission, or else to cap the well and save it until they could get a better price. I don't know which course of action it should take." (110: 14,663, lines 20-24)

However, somewhat later Chapin modified this position as follows:

> "If it is in the public interest that the gas be sold, rather than capped and saved for a better market—and I assume it would be so determined in the public interest—then there must be some way determined for Phillips to recover that cost. It seems to me an equitable way can be determined, but I have not made any effort to do so in this Exhibit." (10: 14,669, lines 4-9)

It is interesting to note, however, that the Southern brief (pp. 33-34) while stressing the Chapin recommendation that customers buying Panhandle and Hugoton gas should not be required to pay the higher costs associated with gas produced in higher cost areas, makes no mention whatsoever of the Chapin qualification referred to above.

Among other things, the use of an area-pricing approach based upon a separate cost of service for each producing area is regarded as unsatisfactory for the following reasons:

(1) One of the arguments most stressed by the parties favoring an area-pricing approach is that different producing areas each have different cost levels of their own, and that separate rates should, therefore, be fixed for each area reflecting such varying cost levels. However, the persuasiveness of this argument is diminished when it is recognized that a substantial portion of the costs which have to be assigned to each separate area actually do not represent direct area costs which are clearly identifiable as such, but instead represent over-all, system-wide costs which must therefore be allocated between the different areas on one basis or another. Accordingly, although under this area-pricing approach it would still be necessary to conduct a separate rate proceeding for each individual producer, each

such proceeding would become more complicated in that it would require the development of a multiplicity of different area cost-of-service studies for the individual producer. With respect to each of these different area cost-of-service studies it would become necessary, in addition to the various allocation problems already discussed in this decision, to make further allocations for the purpose of assigning the appropriate portion of system-wide costs to each of the different areas, and the results obtained would, of course, depend upon the method adopted for the making of such further allocations.

(2) The area-pricing approach would also add to our task the problem of selecting logical and meaningful costing or rate areas in each producer rate case, with results varying significantly on the basis of the costing or rate areas selected. This question alone would provide the basis for substantial controversy.[206]

(3) If such an area pricing approach were adopted it would not eliminate the situation, criticized by some, under which a given pipeline purchasing gas from a number of different producers in the same field would be paying a different price to each different producer for the same type of gas, depending upon the cost of service established

for each. It is true that the cost of service developed for any producer, including Phillips, in a high-cost producing area would normally be higher than the cost of service for the same producer in a low-cost area. However, this does not mean at all that the Phillips cost of service in any given area would necessarily be the same as that of another producer for the same area. The fact is that the same factors which result in two different producers having a different

[206] See, for example, the attack made upon the "pricing areas" used by the Staff in the instant proceeding.

system-wide cost of service would similarly result in each showing a different cost of service for any given area.

(4) It is also important to note that, apart from the Staff area-price presentation which is here found unacceptable, the instant record does not contain the evidence required to develop area rates on the basis of a separate cost of service for each producing area. This is true despite the fact that all parties desiring to develop area rates on this basis were provided with all reasonable opportunity to do so in the course of the lengthy hearing.[207] It is, therefore, clear that in order to fix rates in this proceeding on the basis of an area-pricing approach, based upon a separate cost of service for each area, it would become necessary to reopen the record and to now embark upon a new hearing of indeterminate duration, directed to this particular problem. Such a reopened hearing would not be a brief and simple proceeding, since the development of costs on a real area basis would require the redevelopment, from a totally different approach, of many of the major problems which have already been fully tried out in this proceeding on a system-wide basis.

C. *Eastern's Area-Pricing Proposal*

As previously noted, Eastern contends that the Phillips cost of service in this proceeding should be determined on a system-wide basis, and not upon an area basis. In this connection, Eastern states:

> "While Phillips and the Eastern Seaboard Companies have presented sharply differing cost-of-service studies (Exhibits 282 and 388), there is no difference between

[207] As set forth in detail at pp. 2-5 of this decision, the requests made by Wisconsin and the Staff, in the closing stages of the hearing, for a recess of indefinite duration to permit them belatedly to gather and present additional and different area cost data, were clearly unjustifiable and not in the public interest.

them as to the soundness and practicability of determining the Company's jurisdictional costs on an overall or company-wide basis.

"We are aware of the fact that some parties to this proceeding contend that Phillips' rates should be

determined on the basis of its separate costs of service in individual producing areas. Such a contention, of course, presupposes that these particular producing areas can first be established on some meaningful and reasonably non-controversial basis. The record in this proceeding fails to support the propriety of subdividing arbitrarily a reasonable and manageable costing area, large though it may be. Especially is this so when we realize that a very substantial portion of Phillips' total costs is incurred in its nation-wide exploratory activity." (initial brief, pp. 17-18)

However, Eastern proposes that once Phillips' total revenue requirements have thus been determined on the basis of a system-wide cost of service, they should be translated into area rates in a new and second step of the proceeding. The Eastern suggestion as to how this objective might be accomplished was made for the first time by its witness Caplan in the closing stages of his cross-examination. Caplan urged that any general rate adjustment should be accomplished with the least possible disturbance to existing market relationships, and he stressed the importance of preserving existing contract arrangements and existing contract prices to the fullest extent consistent with sound regulatory objectives. He suggested that a simple way to accomplish this objective would be to permit the addition to each individual contract rate of a uniform percentage or cents-per-Mcf adjustment, across the board, sufficient to

return to Phillips the full amount of any deficiency determined in this proceeding. (117: 15,748-50; 15,753-54)

When asked whether he would recommend the application of such an adjustment differential to contracts entered into in recent years at rates as high as 15.65 cents per Mcf, as distinguished from contracts entered into many years ago at rates as low as 3 cents or 4 cents per Mcf, Caplan at first replied:

> "Well, it would be a simple way of doing it but I would like to add that I am dealing mainly with old gas, rather than new gas. I recognize that new gas is a separate problem." (117: 15,751, lines 1-3)

However, he then proceeded to explain that he was proposing this method only for application to those contracts which were in effect in 1954, stating:

> "Q. Would it follow, then, that you would apply 3 cents across the board on all contracts, we will say, in effect at the end of 1956, in order to recoup to Phillips any any increase in revenue?

> "A. No; I think you would have to start with the 1954 contracts for this purpose, and treat the contracts entered into after 1954 separately.
>
> "Unfortunately, I have no advice to give on the contracts entered into after 1954. I was only trying to deal with this structure of rates of the test year." (117: 15,751, lines 11-20)

Caplan expressed the view that any such proposals as referred to above should be initiated, in the first instance, by directing Phillips itself to file recommended rates designed to yield the total cost of service here determined, prepared in the light of its existing contractual relation-

ships and the existing market situation. This suggestion was based upon the assumption that Phillips is in close and intimate contact with its customers, and is therefore in the best position to understand the effect of any price changes on market relationships. (117: 15,749-50; 15,754)

The rate proposal as thus made in Caplan's testimony has since been somewhat refined in the initial brief submitted by Eastern, where the final recommendation is now made as follows:

(1) Eastern argues that historic market arrangements and differences in price levels should be disrupted as little as possible, but that at the same time there should be eliminated the distorting effect of favored nation and spiral escalations which took place since 1954.

(2) Eastern accordingly recommends that the Commission should instruct Phillips to file rate schedules designed to meet these objectives. In this connection, Eastern states:

> "A rate structure so approved and filed would not become effective, of course, until approved by the Commission. All interested and affected parties would have a chance to be heard and criticize it.
>
> "While it might be argued that this would perhaps require a second or rate-making phase of this already protracted proceeding, we believe it offers the most reasonable solution to a difficult problem." (Eastern initial brief, p. 56)

(3) Finally, Eastern suggests that, in the event the Commission should consider it desirable to establish rates in this proceeding without the benefit of such further suggestions by Phillips, then area prices should here be established by spreading any rate increase herein approved, over and above the Phillips rates lawfully in effect in 1954, among all of Phillips customers, on either a flat cents-per-

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Mcf or a percentage increase per Mcf basis, applied to June 7, 1954 prices. By way of illustration, it is suggested:

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> "For example, if the Commission determines that Phillips requires additional revenue equivalent to one cent per Mcf, or, say 10 percent above 1954 levels, a possible simple, direct and appropriate procedure would be to increase such contract prices by, as the case may be, either one cent per Mcf or by 10 percent." (initial brief, p. 57)

Eastern did not spell out in any further detail the manner in which it would apply this "area-pricing" approach, and made no presentation to indicate the contract prices which would result from the application of this method to the cost of service computed by it in this proceeding. However, the proposed method may be characterized as providing for a separate rate to be fixed for each jurisdictional contract on the basis of (a) *a base price*, consisting of the contract price as of June 7, 1954, plus (b) a uniform increment, determined either on a flat-cents-per-Mcf or a percentage basis, derived by distributing the total deficiency equally over the entire volume of jurisdictional sales.

The Caplan proposal would seem to have a certain superficial attractiveness, at first blush, for those who are impressed with the argument that any rates fixed for an independent producer should in some way reflect differing cost levels between one producing area and another. It would also seem to be attractive to those who are impressed with the suggestion that such rates should not be permitted to disturb, any more than is absolutely necessary, the pricing patterns and market arrangements which Phillips' pipeline customers have built up over the years, based upon the purchased gas costs which they have historically incurred. The initial attractiveness of the Eastern proposal lies in

the fact that, in a rather minor way, it makes a nod in the direction of both of these problems.

However, upon more careful analysis, it appears that this method actually is neither a system-wide cost method nor an area cost method, and that its disadvantages in fact outweigh the advantage of its seeming simplicity. It is true that the Eastern method would result in and perpetuate widely different rate levels as between one contract and another. However, such rate level differences would not actually reflect the differences in *cost* as between the gas delivered under the various contracts. Instead, it would simply freeze and continue in effect the price differences between the various Phillips contracts which had come into being by June 7, 1954, not necessarily or only as the result of *cost* differences, but because of such other factors as: (a) industry circumstances prevailing when the different contracts were negotiated; (b) what the traffic would bear when each contract was negotiated; (c) the impact of favored nation and spiral escalations. In addition, under the Eastern method there would now

be added to these different contract price levels (based upon such historic, non-cost factors) a system-wide incremental factor, which would in itself be derived on the basis of a system-wide cost of service. It is interesting to note, in this connection, that Eastern itself states

> ". . . it is our position that the Commission should fix Phillips' rates with a view to the establishment of a meaningful overall rate structure which can be equitably applied to the Company's entire jurisdictional business—thus avoiding the gross distortion of existing price relationships and the severe inequity that would result from the application of any rate-making theory which would recognize and incorporate the favored nation concept." (initial brief, p. 55)

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However, the Eastern method, for the reasons outlined above, would clearly not accomplish this objective. It would freeze in and perpetuate the distortions in price relationships *as they existed on June 7, 1954*, including some relatively high price levels resulting from the impact of favored nation escalations which had already become effective by that date. The only distortions which would in fact be eliminated under the Eastern method would be those which had become effective *after* June 7, 1954.

It is also of interest to note that many of the June 7, 1954 prices under Phillips' jurisdictional contracts were at levels substantially in excess of the system-wide unit cost of service determined for Phillips in this decision. The effect of here adopting Eastern's area-pricing proposal would be to freeze such excessive June 7, 1954 rates as the "base price factor", and to raise them still higher by adding thereto the uniform increment required to recoup Phillips' over-all deficiency. In such situations, the total rate thus approved for some contracts under the Eastern method might be even higher than the rate which would have been derived for such contracts on the basis of constructing a separate cost of service for each producing area.

In an earlier part of this decision, it was concluded that the required Section 5(a) determination, under the standards laid down by the Supreme Court in the *Sierra Pacific* case, *supra*, should be made here, on the ground that there otherwise would be preserved for Phillips an unduly discriminatory general rate structure, which would be contrary to the public interest—i.e., a rate structure including prices which as of June 7, 1954 ranged from a low of 1.1710 cents per Mcf to a high of 15.6509 cents per Mcf. (Exh. 323) The Staff's reply brief argued strongly in this connection that the Phillips contract

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rates vary so widely, even as between contracts for the same service from the same producing areas, as to patently

contravene the public interest, generating and perpetuating undue preference and undue discrimination; that this resulted in a rate structure completely adverse to the very principles and purposes of the Natural Gas Act.

However, under Eastern's area-pricing method the result would be to permanently freeze in and perpetuate such distortions, in a manner going far beyond the situation which would have prevailed in the absence of Federal Power Commission regulation of the independent producers. In the absence of such regulation, Phillips' old, long-term contracts with abnormally low prices, which were still in effect as of June 7, 1954, would ultimately have expired, and its pipeline purchasers would then have been required to renegotiate such contracts at higher price levels in line with the then prevailing price levels in the particular producing area —or, in the case of contracts containing escalation clauses, the contract price might well have escalated to the prevailing price levels of the area even before the expiration of the contract terms. Under the Eastern method, however, these particular contracts would have their *base price* frozen permanently at the abnormally low price level in effect on June 7, 1954, even though that price may have been substantially out of line with the currently prevailing price level for the area at that time.

Entirely apart from the problems outlined above, it must be borne in mind that Eastern's area-pricing method was presented only sketchily, at the close of Caplan's cross-examination. It raises many problems which Caplan himself testified had not yet been worked out in his own mind—i.e., the problem of contracts entered into after 1954, as to which Caplan stated:

> "Unfortunately, I have no advice to give on the contracts entered into after 1954." (117: 15,751)

If the method were to be given further consideration in this proceeding, it would certainly require more extended pres-

entation and development than that so far provided. As a matter of fact, Eastern itself recommends that if this approach is to be adopted it should be initiated by Phillips itself filing recommended rates which all interested and affected parties would then have an opportunity to consider, evaluate and criticize in a second or rate-making phase of this proceeding.

For reasons which will be outlined in greater detail at a later point, it is concluded that the public interest would not be served by throwing the instant proceeding back into another hearing phase of unlimited duration. For this reason, and for the other reasons outlined above, it is concluded that Eastern's area-pricing approach does not provide a useful solution for the rate-making problems involved in this proceeding.

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D. *The Phillips System-Wide Rate Approach*

As noted at an earlier point, Phillips here uses a system-wide rate approach under which uniform rates are proposed for all customers, based upon its system-wide cost of service, with rate differentials to reflect four different delivery condition factors.

Interveners such as El Paso and Panhandle, and the distribution company customers whom they supply, contend that a major portion of their gas supply from Phillips comes from relatively low-cost producing areas, such as the Panhandle-Hugoton field; that they do not now and do not expect in the future to derive any benefit from Phillips' high-cost exploration and production in other areas such as the South Louisiana area; that they accordingly should not be required to incur the burden of any of these "other area" costs except with respect to gas which they may in fact purchase from such areas. Southern witness Chapin stated this position as follows:

". . . it is obvious that customers buying Panhandle and Hugoton gas which has been developed at relatively low cost, should pay accordingly lower prices.

"When, as and if these or any customers purchase additional gas from other higher cost areas now being explored and developed, they should properly pay the higher costs associated with that gas. No such distinction is provided in the uniform rate plan proposed by Phillips." (96: 12,787, lines 17-24)

Although it may be true that most of the gas supply currently purchased by interveners El Paso and Panhandle Phillips comes from the lower-cost Panhandle and Permian Basin areas, the fact is that the higher cost exploration and production carried on by Phillips in the Southern Louisiana area redounds ultimately to the benefit of El Paso and Panhandle. This is because the discovery of additional gas reserves in other areas, even if El Paso and Panhandle were never in the future to take delivery from such areas, would have the effect of improving the total nation-wide reserves and thus reducing the pressure upon the existing reserves from which El Paso and Panhandle currently draw the major portion of their gas supply. In addition, the fact is that because of the interrelation of lines and the multiple possibilities of exchange, pipeline companies may receive benefits from new supplies developed virtually anywhere in the United States.

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Entirely apart from the above, however, El Paso itself has been laboring under a substantial gas supply problem which has already required it to obtain new sources of supply in other, higher-cost areas. In recent orders the Commission has stressed the importance of El Paso's continuing

its efforts to improve its over-all reserve position.[208] In order to solve this problem, El Paso has been engaged in recent certificate proceedings before this Commission seeking authorization under Sec. 7(c) of the Natural Gas Act to purchase substantial additional gas reserves: (1) from producers, *including Phillips,* in the Aneth Field area, in the vicinity of the boundary point connecting the states of Utah, Colorado, New Mexico, and Arizona, at contract prices ranging as high as twenty-cents per Mcf for residue gas [209]; and (2) from producers, *including Phillips,* from the Bell Lake Field in New Mexico, at contracts carrying an initial price of sixteen cents per Mcf.[210]

It is also relevant to note, in the same connection, that Panhandle already obtains a substantial portion of its gas supply from the South Louisiana area, through its wholly-owned subsidiary Trunkline Gas Company.

The adoption here of a system-wide rate approach would have the effect of holding down to more modest levels the prices which El Paso and Panhandle would be required to pay for such new gas supplies. Thus, although the application of a system-wide rate approach in this proceeding would have the effect of increasing the prices to be paid by El Paso and Panhandle under their old, low-priced contracts, this would be counterbalanced by the limitation imposed upon the prices which they would be required to pay under more recent gas purchase contracts and under new contracts to be negotiated by them in the future.

It must also be borne in mind here that it is vital to Phillips' pipeline and distribution company customers, and to

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208 Order issued December 19, 1956 in Docket # G-10 499; order issued March 26, 1958, in Docket # G-11,797.

209 See Initial Decision of Presiding Examiner *In the Matters of El Paso Natural Gas Co., et al.,* Docket Nos. G-12,580, *et al.,* issued February 26, 1959.

210 See Initial Decision of Presiding Examiner *In the Matters of Continental Oil Co., et al.,* Docket Nos. G-13,453, *et al.,* issued February 18, 1959.

the consumer, that Phillips be encouraged to continue a high level of exploration activity. However, if Phillips' rates were fixed on an area-pricing basis, the results might well be such as to defeat this objective. In order to

meet the continually increasing requirements for natural gas reserves, it is important that exploration in the newer and higher-cost areas should be continued and expanded. Such operations might conceivably, in some cases, result in an area cost of service calling for a higher price than pipeline purchasers would be able or willing to pay on an area-rate basis. If Phillips, under such circumstances, were required to absorb the resulting deficiency, it might be compelled to reduce or eliminate its program of exploration and production from such areas—a result which would clearly not be to the advantage of its pipeline or distribution customers, or the consumers.

Similarly, in situations involving exploration and production in a newly-developed area (such as off-shore gas), initial costs would be unusually high and the volume of sales would be relatively low in the early stages. As a result, pipeline purchasers might not be willing to purchase gas from such an area during the initial development period, if the rates therefor were fixed on the basis of an area cost of service. If Phillips, in such a situation, were required to shoulder the resulting deficiency the effect would be to discourage exploration activity in such new areas.

In addition, entirely apart from the problems referred to above, the adoption of an area-pricing approach here would mean that pipeline customers purchasing gas from such newly-developed producing areas in the initial, high-unit-cost years would be required to exclusively shoulder the burden of such high initial costs. Because of the expanding requirements of interveners such as El Paso and Panhandle, and the continuing depletion of reserves in the older and

lower-cost Panhandle area, it is entirely conceivable that such other newly-developed producing areas may become of vital importance to these interveners at some future date. Yet, under their proposed area-pricing approach, if El Paso and Panhandle should later commence to purchase gas from such other areas, at a time when unit costs had dropped to lower and more normal levels, they would then obtain the benefit of reserves which could not have materialized without the high unit cost operations of the earlier years, although they would have incurred no part of the burden of such earlier development period.

Another basic objection made by the Staff and the interveners to the system-wide rate approach is that it disregards wide differences in costs incurred in producing and selling gas as between different areas on the Phillips system. In this connection, the Staff contends that

> "where there is a difference in costs of service as between areas or as between various sales there is a necessity to deviate from uniform rates and the Commission has heretofore recognized this necessity and has effectuated a policy with respect thereto." (initial brief, p. 131)

It is difficult to reconcile this Staff position with the fact, already set forth at length at an earlier point of this decision, that the Staff itself has here constructed a "cost" for all casinghead and condensate gas produced on the Phillips system which is not based upon the actual costs of such gas produced in any given area, but is instead derived by imputing thereto the cost of producing *dry gas* in the Panhandle-Hugoton field.

Furthermore, we know of no basis for the Staff's suggestion, in the statement quoted above, that the Commission "has effectuated a policy" against the use of uniform rates "where there is a difference in costs of service as between

areas". As a matter of fact, the adoption of the system-wide rate approach in this proceeding, reflecting the rate differentials proposed by Phillips to cover its four different delivery condition factors, would mean that each pipeline purchaser receiving the same class of service would pay the same rate. It is concluded that such a result would in no way be inconsistent with Commission policy or with the requirements of the Natural Gas Act.

Another argument made against the system-wide rate approach is that it ignores and needlessly disrupts "the many historical market relationships developed between the Company and its customers over the years". Eastern contends that

> ". . . a well-designed rate schedule should recognize and disturb as little as possible the established relationships which Phillips has with its customers, insofar as they are consistent with sound regulatory principles and objectives." (Eastern initial brief, pp. 55-56)

It is to be noted, however, that Eastern witness Caplan testified that an area-price approach based upon a separate cost of service for each producing area would in fact be subject to the same criticism. (117: 15,748) Furthermore, from a realistic standpoint, this argument loses its persuasiveness when it is recognized that the uniform system-wide rate approved in this decision amounts to only 11.662 cents per Mcf, which is not strikingly higher than the weighted-average field prices in the Panhandle and Permian Basin areas, and which is somewhat lower than the nationwide average price of 12¢ per Mcf paid by interstate pipeline companies for gas purchased directly from independent producers in 1957.[211] In addition, the objection to the sys-

[211] See report issued by the Commission on November 13, 1958, entitled "Direct Sales By Producers Of Natural Gas To Reporting Interstate Natural Gas Pipeline Companies—1957."

tem-wide rate approach as disrupting historical market relationships developed between Phillips and its customers over the years, loses its impact

when it is recognized that, in the absence of Commission regulation of independent producers, many of the Phillips low-priced contracts in the Panhandle and Permian Basin areas would have moved to higher price levels in any event, as escalation clauses became effective.

A final objection made by Eastern to the system-wide rate approach is that

> ". . . it would in reality establish on a company-wide basis the same favored nation concept of a rate making that the honoring of individual favored nation clauses would establish on an area or field basis." (initial brief, pp. 55-56)

Favored nation escalation clauses are regarded as contrary to public policy because of the fact that they automatically bring about producer rate increases without regard to whether a given producer's costs warrant or justify such increases—i.e., such clauses, by their terms, are triggered solely by the fact that a higher price may have been paid under some other contract in the prescribed area. Clearly no such complaint can be made under the instant system-wide rate approach, where rates are established for Phillips on the basis of its system-wide cost of service. This Eastern contention is therefore regarded as unimpressive.

After considering all of the matters outlined above, it is here concluded that the system-wide rate approach represents a satisfactory and appropriate method for the fixing of "just and reasonable" producer rates, for the following reasons:

(1) It is inherently simple to administer.

(2) It would be fair to the producer, in the sense that it permits him to recover his total cost of service in one way or another.

(3) It would eliminate unreasonable preferences currently enjoyed by pipelines which are still purchasing gas under old, abnormally low-priced contracts—preferences which are based not merely upon differences in cost levels, but which reflect other historic reasons.

(4) Although the effect of a system-wide rate would be that pipelines such as Panhandle and El Paso, which are presently enjoying abnormally low prices under certain old, long-term gas supply contracts, would be required to pay a higher price level under such contracts, this would be only a short-term, temporary disadvantage. Furthermore,

any such temporary disadvantage would be counterbalanced by the fact that their necessary purchases of additional gas reserves from more recently developed and higher-cost areas would be made at lower rates than would have resulted under an area-pricing method.

Entirely apart from what has been said above, it makes sense to adopt the systems-wide rate approach in the instant proceeding because:

(1) The Staff's area-pricing method is unacceptable.

(2) The Eastern area-pricing proposal is also regarded as unacceptable.

(3) A conventional area-pricing method, based upon the construction of a separate cost of service for both dry gas and associated gas for each different producing area, is regarded as undesirable. In addition, such a method could not be applied on the basis of the record made in this proceeding, and its adoption would therefore require reopen-

ing the proceeding for a further hearing of indeterminate length. This would not be in the public interest.

It is not only appropriate but essential that the Commission, at this beginning stage of its resolution of the problems involved in producer-rate fixing, should make a serious study of various possible rate-making approaches—in order to finally select a method which will be fair and reasonable to all segments of the natural gas industry and to the consumers, as well as administratively workable. It was in this vein that the Court of Appeals for the Fifth Circuit, in its decision issued February 20, 1959 in *Forest Oil Corporation, et al.*, v. *Federal Power Commission, supra*, mentioned as a possibility for Commission consideration "a uniform price for all of the producers of a single well or a single field". It may be that the Commission, after serious study, may wish to give consideration to the possibility of developing area prices, based upon an industry-wide cost of service for each area, which would be applicable to all producers in such area. However, no such presentation was made in the instant proceeding, and it is clear that the adoption of any such method could not properly be accomplished in a rate proceeding involving a single producer. Furthermore, adequate evaluation of the usefulness and desirability of any such approach would require a major and detailed study, such as has not yet been made in any producer rate case which has reached the point of decision. Among other things, consideration would have to be given to such matters as whether the constitutional prohibition against confiscation might prevent the application to a given producer of an area rate thus derived, which was lower than its own cost of service for such area.

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The adoption of the system-wide rate approach in this proceeding, of course, would not necessarily mean that this basic problem is thus being finally disposed of for all time.

The Commission is here only at the threshold of working out satisfactory solutions to all the key problems involved in the regulation of independent producer rates, and it would be quite unrealistic to expect that all of these difficult and important problems can be solved, for all time, in this one proceeding. The most important contribution which could be made to the industry and the public interest at this time—five years after the date of the Supreme Court's *Phillips* decision—would be to finally close the instant case and speed it on its way to a final decision by the Commission, and later by the Courts. It is also to be hoped that the matters discussed herein will help to bring into sharper focus the real problems to which the Commission will wish to devote further serious attention, not only in its consideration of the instant case but in its consideration of other major producer rate cases now in various stages of hearing before the Commission.

XXIII. RATES PROPOSED BY PHILLIPS WITNESS MAYER

A. *Rate Differentials For Varying Conditions of Delivery*

As previously noted, Phillips witness Mayer considered the effects which varying conditions of delivery should have on prices, and concluded that the following four factors should be reflected for this purpose: (1) point of delivery, (2) pressure, (3) whether dehydrated or undehydrated, and (4) whether sweet or sour. He then established various price differentials, reflecting average conditions, for each of these varying types of delivery. In order to arrive at the proposed rate for each contract, Mayer first calculated, on a basis which will be explained at a later point, a "maximum rate for 1,000-pound, sweet, dehydrated, and gathered gas" —i.e., for gas delivered under the *optimum* conditions with respect to these four factors. In the case of each contract he then deducted from such maximum rate" the particular

delivery condition price differentials applicable to that sale. These price differentials were established as follows:

(1) For wellhead sales at various pressures—1 cent per Mcf at 1,000 pounds; 1.1 cents at 800 pounds; 1.2 cents at 650 pounds; 1.3 cents at 500 pounds; 2 cents at 200 pounds; 2.5 cents at 100 pounds.

(2) For sales of gathered gas at various pressures—0.50 cents per Mcf at 800 pounds; 0.75 cents at 650 pounds; 1 cent at 500 pounds; 2 cents at 200 pounds; 2.75 cents at 100 pounds; 3.75 cents at 40 pounds.

(3) An allowance of 0.25 cents per Mcf was made for dehydration.

(4) For purification or sweetening of sour gas, an allowance of 0.40 cents per Mcf was made for Panhandle sour gas; 0.75 cents per Mcf for all Permian Basin sour gas, except the Crane plant; 1 cent per Mcf for the Crane plant gas in the Permian Basin, because it was unusually sour.

Neither the Staff nor the interveners have challenged the rate differentials referred to above. They appear to be reasonable, and are hereby adopted for the purpose of the instant decision.[212] As noted above, after Mayer determined

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212 El Paso has contended (initial brief, p. 35) that an additional differential should be established for plant residue gas, to reflect the fact that pipeline customers incur various inconveniences and disadvantages with respect to purchases of plant residue gas, due to their lack of control over the volumes to be received at any given time. El Paso notes that substantial volumes of plant residue gas are included in its purchases from Phillips. In the course of interrogation by El Paso counsel on this subject, Phillips witness Mayer stated:

"Well, that w[illegible] be another factor, Mr. Horning, that would fall in the category of so[illegible] of the others that we mentioned; that perhaps in arms' length negoti[illegible]ion might have been given some weight, *but I would certainly know of no way to place any value on it here.* In [illegible]e first place,

his recommended rate differentials for the four delivery condition factors, his next objective was to arrive at a given "maximum rate for 1,000 pound, sweet, dehydrated, and gathered gas". The "maximum rate" selected was one which, when applied to the sales volumes delivered in 1954 under each of the contracts as to which he here proposes specific rates, as adjusted for such rate differentials, would produce a dollar amount which, when added to the revenues collected under existing contract rates for the other contracts, would roughly equal Phillips' claimed jurisdictional cost of service. Using a trial-and-error process, he found that a "maximum rate" of 22.75 cents per Mcf for gas delivered under such *optimum* conditions would produce the desired result, based upon his Exh. 324.

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B. *Categories of Sales For Which Phillips Proposes No Rates*

Mayer abstained from proposing specific rates for three different categories of rate schedules: (1) percentage-type casinghead gas contracts, involving 111 rate schedules (Exh. 288, Sched. I); (2) "*de minimis*" schedules, covering sales averaging less than 400 Mcf per day; and (3) terminated rate schedules. (Exh. 288, Sched. II) He contemplated that Phillips' rate schedules for the first two categories would continue at their present levels.

The Phillips contention that no rates should be fixed in this proceeding for its jurisdictional sales under percentage-type casinghead gas contracts has already been discussed

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it is an unknown condition, if you are talking about future operations." (90: 12,183, lines 7-13, emphasis supplied)

As a matter of fact, El Paso made no attempt, either through evidence or in its briefs, to suggest how a rate differential could be devised which would reasonably reflect this situation. Under these circumstances, it is not possible or appropriate to give further consideration to this matter on the instant record.

in detail and rejected at an earlier point in connection with the issue of "Phillips' Increased Purchased Gas Cost Adjustment". The contention that no rates should here be fixed for *de minimis* contracts is also regarded as unacceptable. In this connection, we agree with the Staff position (initial brief, pp. 142-143) that the requirement set forth in Section 4(a) of the Natural Gas Act that

> "All rates and charges made, demanded or received by any natural-gas company for or in connection with the transportation or sale of natural gas . . . shall be just and reasonable"

applies with equal force to all jurisdictional sales, without regard to the volumes involved. In addition it is, of course, not inconceivable that sales under a given contract which were *de minimis* during the test year might increase to substantial levels during succeeding years.

With reference to terminated contracts, it is important to bear in mind that in determining the rates required to produce revenues equal to our test year cost of service, our calculations must be based upon actual 1954 delivery volumes and delivery conditions. In connection with this determination, the fact that some of the 1954 sales are no longer being made is not relevant, since we are here fixing rates based on a matching of 1954 costs with 1954 sales. The rationale in back of the use of a test period is that, although some of the test period operations may later be discontinued, or new operations may be added, the resulting ratio of operating expenses, plant and volume of sales remains roughly the same. An entirely different proposition, however, will be involved when Phillips in compliance with the instant order makes the required filing of proposed rates for its jurisdictional rate schedules. It is assumed that terminated rate schedules will not be included in such filing, since no purpose would be served by fixing a rate for a

contract under which deliveries are no longer being made.

In view of the considerations outlined above, it is concluded that Phillips should here be directed to calculate the given "maximum rate" for gas delivered under the *optimum* conditions, at such level that its application to the sales volumes delivered in 1954 under each and every

one of the 1954 jurisdictional contracts, as adjusted for the above-mentioned rate differentials, would produce total revenues roughly equal to Phillips' system-wide cost of service as approved in this decision.

C. *Rates For Future Sales*

Phillips contends that the instant decision should fix its jurisdictional rates solely with respect to those rate schedules which were in effect in 1956,[213] and that the rates so prescribed should not be made applicable and binding upon any later and future sales. In this connection, Phillips states:

> "Obviously, rates cannot now be fixed for sales which are not yet in existence. The conditions under which those sales will be made are not now known. The Commission's jurisdiction in this proceeding is limited to those sales being made and cannot by some magic be extended to sales which have not yet begun." (reply brief, pp. 139-140)

Phillips witness Mayer testified that the failure to propose rates for contracts entered into subsequent to 1956 was "because there was no investment in the test year to go with them". He stated:

> "I presume that if the Commission feels compelled to consider those new sales, that they will call a new rate

[213] Reply brief, p. 139, footnote 1; Exh. 357.

hearing, Mr. Lamb. I don't know how we can have a test year of 1954 and consider new contracts, sales from new properties in 1957, which were not included in any kind of cost study." (91 ; 12,276, line 17—12,277, line 5)

This position is found to be without merit. Actually, the Phillips rate base as herein adopted includes substantial amounts of undeveloped acreage, as to which no gas reserves have yet been dedicated to sales contracts. Phillips is thus being allowed (over the objection of some of the interveners) a reasonable return upon undeveloped acreage with respect to which no matching volume of sales or revenues is here reflected. This, of course, represents a significant advantage for Phillips.

In addition, however, it is important to bear in mind here that the use in this proceeding of a 1954 test year, with the adjustments

herein approved on the basis of "known changes", is based upon the determination made herein that the relationship of operating expenses, plant and volume of sales for the year 1954, as thus adjusted, is representative of the relationship between these three factors which pertains for the ensuing and future years. If this assumption is sound, it is reasonable to expect that even though some additional facilities might be required in connection with new sales made after 1956, and even though the total operating expenses, plant and volume of sales for such ensuing years might not be identical with such figures for the year 1954, nevertheless the ratio between the three factors would still remain roughly the same. Under such circumstances, if the rates herein approved for Phillips' jurisdictional sales are made applicable to contracts executed in the ensuing years, the overall result should still be the preservation of roughly

the same relationship between operating expenses, plant and revenues.[214] If, however, as a result of significant changes in any one or more of these three basic factors in the future, it should develop that the test year relationship of operating expenses, plant and volume of sales was no longer representative, Phillips would, of course, then have the opportunity to file a new rate proceeding for the purpose of determining a new cost of service and a new level of "just and reasonable" rates based thereon.

It actually does not appear that this situation involves any problems more difficult than those which are disposed of routinely in pipeline rate proceedings. Under the Commission's long-established procedures, the rates approved in a pipeline rate case become the legally effective rates of the pipeline for all future jurisdictional sales, until such rates may be changed in a subsequent rate proceeding.

If, instead, we were here to adopt the Phillips position that the rates herein approved should be made applicable only to contracts which were in existence in 1956, the results would be clearly contrary to the public interest. It would mean that, although it is here concluded that a system-wide rate of 11.662 cents per Mcf represents the "just and reasonable" rate for all of Phillips' jurisdictional sales, nevertheless sales would continue to be made by Phillips under contracts executed in 1957 and 1958 at contract prices which in many cases are substantially

higher than the rate level herein approved. In addition, it would mean that sales under new contracts hereafter executed by Phillips could be made without reference to the

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[214] It may also be noted, in this same connection, that although such new facilities as might possibly be required in connection with new contracts are not reflected in our instant test year rate base, this is counterbalanced by the fact that the corresponding additional volumes of sales and revenues are also not reflected herein.

"just and reasonable" rate level approved in this decision. The only protection to the consumer, under such circumstances, would lie in the possibility of Section 5(a) proceedings instituted by the Commission. Any such remedy, however, would place the consumers at a serious disadvantage, since any reduction in rates which may be ordered by the Commission in a Sec. 5(a) proceeding can take effect only from and after the date of such order—and experience shows that there is an extremely long time-lag between the date of commencement of such a proceeding and the ultimate issuance of the Commission's final decision.[215]

It is concluded that such a result would be inconsistent with the primary aim of the Natural Gas Act to protect the consumers from exploitation, and that it is not required or justified by anything shown in this proceeding. Accordingly, the rates herein approved for Phillips' jurisdictional sales will be made applicable to all jurisdictional sales, whether under rate schedules presently in effect or new sales to be made hereafter—unless and until such rates may be changed by the Commission in a subsequent rate proceeding.

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XXIV. THE SPECIAL ISSUE RAISED WITH RESPECT TO EL PASO, PANHANDLE AND MICHIGAN-WISCONSIN, BY COMMISSION ORDER ISSUED APRIL 26, 1957.

This problem arose when El Paso on March 12, 1957 filed in Docket No. G-11217 (one of the Phillips Sec. 4(e) dockets consolidated herein) a "Motion by El Paso Natural Gas Company to Djsmiss Docket No. G-11217 and Request by

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[215] Commission statistics show that Section 5(a) proceedings in pipeline rate cases have averaged approximately 36 months in duration, with a range of between 73 months and 10 months. (See p. 97 of brief filed with the United States Supreme Court on behalf of the Federal Power Commission in the *Memphis* case, *supra*, August 1958)

El Paso Natural Gas Company for an early Limited Hearing on the Issues Here Presented". El Paso contended in this Motion that Phillips' proposed rate increases in Docket No. G-11217 are void and of no legal effect because they are based upon spiral escalation provisions which are contrary to public policy; that the operation of these spiral escalation provisions had been suspended, and that they were inoperative because the conditions precedent to their triggering had not been fulfilled; that under these circumstances Phillips' rate increase filings in Docket No. G-11217 were illegal and unauthorized under the rate schedules and constituted prohibited unilateral rate filings under the holding of the Supreme Court in the *Mobile* case, *supra;* that such rate filings should accordingly be rejected and the proceeding in Docket No. G-11217 should be terminated.

By order issued April 26, 1957, in this consolidated proceeding, the Commission permitted Phillips' proposed Sec. 4(e) rates in Docket No. G-11217 to go into effect subject to refund; denied El Paso's request for a limited hearing with respect to the above issue; and noted that in addition to this issue as raised by El Paso in Docket No. G-11217, a similar issue was also involved in Dockets Nos. G-10793 and G-10883 which are also consolidated with the instant proceeding. Docket No. G-10793 is a Phillips Sec. 4(e) rate filing covering a sale to Michigan-Wisconsin, and Docket No. G-10883 involves a Phillips sale to Panhandle. The Commission Order noted that the Phillips rate schedules involved in these two latter rate filings contain spiral escalation provisions similar to those complained of by El Paso as being "contrary to public policy", and stated:

> ". . . it is deemed appropriate and in the public interest that the legality of Phillips' rate filings in these three dockets be considered in the consolidated proceedings."

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Accordingly, in paragraph (1) of its findings in the said Order, the Commission directed that the instant consolidated hearing should include among other things:

> ". . . the issues involved in Docket Nos. G-10793, G-10883, and G-11217 whether (a) Phillips' increased rate filings in the proceedings in Docket No. G-11217 for sales of natural gas to El Paso constitute unilateral filings within the meaning of the *Mobile* case. . .;

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> and (b) the spiral escalation provisions contained in Phillips' FPC Gas Rate Schedules Nos. 7, 9, 32, 33, 64 and 243 applicable to sales of natural gas to El Paso and the similar escalation provisions in Phillips' FPC Gas Rate Schedules Nos. 4 and 5 applicable to sales of natural gas to Michigan-Wisconsin and to Panhandle, respectively, are so ambiguous in language and so inflationary in effect as to contravene the public interest and conflict with the regulatory powers of the Commission, or are otherwise unlawful."

As already held in an early part of this decision, under the principle laid down by the Supreme Court in its *Mobile* decision, *supra*, the Phillips rates in existing contracts cannot be changed unilaterally. Accordingly, the Sec. 4(e) rate increase procedure is only available for the rate schedules referred to above to the extent that the terms of the contracts themselves permit such price changes. However, it has also been concluded that the controlling facts in this proceeding do satisfy the Sec. 5(a) standards as laid down by the Supreme Court in the *Mobile* and *Sierra Pacific* cases, *supra*. Accordingly, from and after the date when the rates herein fixed may be finally approved by the Commission (following steps which may be taken by Phillips pursuant to the instant Order), Phillips *would* be entitled

to collect such rates *prospectively*. The Sec. 4(e) issues raised in the El Paso Motion would be entirely irrelevant in this connection, since Phillips' rates are here being fixed solely on the basis of its system-wide cost of service as here determined, and no weight whatsoever has been given in this connection to the spiral escalation provisions of the Phillips-El Paso contracts, which are attacked in the El Paso Motion.

However, this does not dispose of or resolve the question of Phillips' right to its proposed Docket No. G-11217 rates from March 11, 1957, when it commenced collecting such rates pursuant to refund undertaking, to the date when the cost of service rate levels herein approved will become effective prospectively under our Sec. 5(a) determination. That particular question, the resolution of which will determine whether El Paso is entitled to any refund under Docket No. G-11217 for the past refund period, must be resolved under Sec. 4(e). The solution to this particular question will depend upon whether El Paso may be regarded as having consented to such Sec. 4(e) rate increases, by virtue of the escalation provisions contained in the Phillips-El Paso contracts. If this question is answered affirmatively, the Phillips Sec. 4(e) rate filing in Docket No. G-11217 would not constitute a unilateral rate increase, as barred by the *Mobile* doctrine. It would then follow that, since the system-wide unit cost of service herein approved for Phillips exceeds the level of rates proposed by Phillips in its Docket No. G-11217 rate filing, no refund to El Paso would be required in this connection.

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We turn now to a discussion of the spiral escalation provisions involved in these Phillips-El Paso contracts, and the precise contentions made by El Paso in that connection. Throughout this entire discussion it is important to bear in mind that these spiral escalation provisions are referred

to here for the sole purpose of determining whether they provide the basis for a finding of *El Paso consent* to the Phillips Sec. 4(e) rate filing in Docket No. G-11217, such as to free that rate filing from the taint of a unilateral rate increase barred by the *Mobile* doctrine.

El Paso's first contention is that the spiral escalation provisions here involved were contrary to the public interest and therefore void; that accordingly they cannot be regarded as an effective El Paso consent to Phillips' Docket No. G-11217 rate filing. In this connection, El Paso stresses the Commission holding in Op. No. 275, *In the Matter of Michigan-Wisconsin Pipe Line Company*, to the effect that such spiral escalation provisions are

> "inconsistent with the standards of the Natural Gas Act, and contrary to the public interest as a matter of law." (p. 39, Mimeo Opinion)

El Paso accordingly contends that the spiral escalation provisions are a nullity, and that the Phillips-El Paso contracts must be construed as though such provisions had never been incorporated therein; that Phillips' rate filings in Docket No. G-11217 were therefore illegal and unauthorized because they were not made pursuant to a *valid* right reserved in the contracts to apply for increases under Sec. 4(e); that they accordingly constitute prohibited unilateral rate filings within the doctrine of the Supreme Court's *Mobile* decision.

This argument is regarded as without merit. The import of the Supreme Court's *Mobile decision*, as made clear in its later *Memphis* decision, *supra*, was that where the pipeline seller's contract contained no provision for changing the agreed rate during the term of the contract, it had no right to unilaterally abrogate such an unqualified contract obli-

gation and to increase its price to the purchaser at will, subject to the Sec. 4(e) procedure.[217] However,

with respect to the Phillips-El Paso contracts here involved we have an entirely different situation. Here the two parties admittedly had agreed in their original basic contract that the initial contract rate might be changed from time to time during the term of the contract under the escalation mechanism. Furthermore, these agreements were executed prior to the time when this Commission embarked upon its regulation of independent producers, under the Supreme Court's *Phillips* decision of June 7, 1954, and prior to the time when the Commission expressed its position that such spiral escalation provisions were contrary to the public interest. It should also be noted that the El Paso theory that the escalation provisions should be treated as a nullity for the purpose of this particular problem is squarely contradicted by the holding of the Court of Appeals for the Tenth Circuit in *Phillips Petroleum Company* v. *F.P.C.*, 227 F 2d 470 (1955), and *Kerr-McGee Oil Industries, Inc.* v. *F.P.C.*, decided October 24, 1958. In both of these cases the Court determined the legally effective rate of the producer, as of June 7, 1954, by giving effect to similar spiral escalation provisions contained in contracts between the producer and its purchaser.

It would, of course, be clearly contrary to public safety to allow rates to be increased automatically under spiral escalation provisions without regard to whether the producer's costs warrant or justify such increases. However, the same objection is not applicable to merely treating the escalation provisions as representing customer consent which renders the Sec. 4(e) procedure available here to Phillips—so long as the determination of just and reasonable rates under

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217 *United Gas Pipe Line Company* v. *Memphis Light, Gas and Water Division, et al.* (December 8, 1958), page 6 of slip-sheet opinion.

Sec. 4(e) is then based exclusively upon Phillips' cost of service.

In addition to the argument discussed above, El Paso further contends that even if the mentioned escalation provisions are not to be regarded as a nullity, they failed to become operative for reasons which will now be set forth. The Phillips-El Paso contracts, which are on file as Phillips' Rate Schedules Nos. 7, 9, 32, 33, 64 and 243, contain an escalation provision providing that when the commodity index shall have increased more than a prescribed number of points and a general increase in El Paso's rates shall have been put into effect, then Phillips' rates shall be increased in proportion to such increase in El Paso's rates. On January 1, 1953, Phillips and El Paso executed an amendatory contract, amending each of the contracts identified above. By Article VIII of this Amendatory Agreement, a new escalation provision was adopted for each and every one of these contracts, providing:

> "no adjustment shall be made unless and until (1) the Annual Index shall be more than 19.06 points above the level 66.7 and El Paso shall have had an increase in resale rates. . . . When revised rates shall become effective during any adjustment period, the price for gas delivered hereunder shall be adjusted to a price which bears the same ratio to the price provided in Sec. 1 of this article which the revised resale rates bear to the resale rates in effect immediately prior to revision."

In addition, Article X of the Amendatory Agreement provided that these escalation provisions should be inoperative until El Paso by final decision of the Federal Power Commission should receive in full certain rate increases in the amount of $12,142,803 which had been applied for and which

were the subject of proceedings then pending before the Commission in Docket No. G-2018; that the escalation provision should then again become effective and thereafter an adjustment in Phillips' rates would occur whenever revised rates for El Paso should become effective.

It is not disputed that the Commission on July 20, 1956 did issue a final order in Docket No. G-2018 approving a settlement between El Paso and its customers, under the terms of which El Paso, effective January 1, 1954, received the full rate increases sought in that proceeding. In its "Answer To Petition Filed For Shortening of Suspension Period . . .", filed with the Commission on January 14, 1957 in Docket No. G-11217, El Paso stated that it

> ". . . did receive the full rate increases sought in that proceeding effective as of January 1, 1954."

However, El Paso contends that because the full rate increase which it received in Docket No. G-2018 was made effective only for the period commencing January 1, 1954, and did not cover the period from January 1 to December 31, 1953, it has not in fact received the "full" increase sought in that docket; that accordingly the terms of Article X of the Amendatory Agreement of January 1, 1953 were not satisfied, and the escalation provisions in the mentioned Phillips-El Paso contracts are therefore still not operative.

This theory cannot be regarded as having any serious merit. It was the clear purpose of the suspension provision contained in Article X of the Amendatory Agreement of January 1, 1953 to render the escalation mechanism temporarily inoperative until El Paso received Commission approval for the $12,142,803 rate increase proposed by it in Docket No. G-2018. However, it is not reasonable to suggest

that even though the El Paso rate increase was approved for this entire amount, the mere failure of the Commission

Order to make the full increase effective from the very beginning of the refund period would be sufficient to render the escalation mechanism permanently inoperative. It is, therefore, concluded that the conditions laid down by Article X of the Amendatory Agreement of January 1, 1953 were satisfied by the Commission's final order issued July 20, 1956 in Docket No. G-2018, and that, accordingly, the escalation provision of the original contract thereupon again became effective.

Following the termination of the proceedings in Docket No. G-2018, El Paso filed a further proposed rate increase under Sec. 4(e) which became the subject of Docket No. G-4769. These revised rates were allowed by the Commission to become effective on April 15, 1955, pursuant to refund order. It is this second El Paso increase which was treated by Phillips as triggering the escalation provision, and which accordingly became the basis for Phillips' own rate increase proposal in Docket No. G-11217, filed September 10, 1956. In Docket No. G-4769 an Initial Decision issued by the Presiding Examiner is presently pending before the Commission on appeal, but no final decision has yet been issued.

Entirely apart from its first argument outlined above, El Paso contends that the escalation provision contained in the Phillips-El Paso contracts can be triggered only by a *final* decision increasing El Paso rates; that the fact that El Paso is presently collecting the Docket No. G-4769 rate increases subject to refund is not in itself sufficient to make the escalation provision effective; that until the amount of the increase in resale rates, if any, to which El Paso will become entitled by final decision of the Commission in Docket No. G-4769 is determined, any application by Phillips for a Sec. 4(e) rate increase, based upon such escalation provision, is premature.

In answer to this contention, Phillips stresses the fact that, in contrast with the escalation suspension provision

contained in Article X of the Amendatory Agreement, which speaks in terms of a "final decision" to be entered by the Commission with respect to Docket No. G-2018, the basic escalation provision in Article VIII of the Amendatory Agreement requires only that revised rates for El Paso "shall become effective" in order to trigger the escalation clause. Phillips therefore contends that even though the El Paso rate increases in Docket No. G-4769 are still being collected subject to possible refund, they are nevertheless "effective" within the meaning of the escalation clause referred to above. This argument goes too far. The basic escalation provision provides that

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when the stated conditions are satisfied, the existing Phillips rate should be escalated in the same ratio as the rate increase received by El Paso. The adoption of the Phillips rationale would require an assumption that the escalation provision permitted Phillips to increase its price to El Paso in the same ratio as the increase *proposed* by the latter in its G-4769 filing, without regard to whether the Commission might ultimately disapprove all or a part of such rate increase proposal. Such an interpretation, however, is regarded as unreasonable.

It is concluded here that when El Paso commenced collecting its proposed G-4769 rates subject to refund, the escalation provision in the Phillips-El Paso contracts became operative *on a tentative basis*, in the sense that the precise amount of the increase triggered by such escalation provision was contingent upon the ultimate resale rate to be finally established by the Commission for El Paso in that docket. When the Commission ultimately determines the El Paso rates under Docket No. G-4769, the precise amount of the Phillips increase triggered by such escalation provision will then be established retroactively by relation back to the beginning of the refund period in Docket No. G-

11217.[218] If the amount of the Phillips escalation increase, determined on that basis, should be less than the amount of Phillips' proposed Section 4(e) rate increase to El Paso in Docket No. G-11217, it would follow that any such excess portion included in the G-11217 rate filing would constitute a *unilateral* increase barred under the *Mobile* doctrine. Any such excess portion would then be recoverable by Phillips, if at all, only *prospectively* on the basis of the Sec. 5(a) finding made in this decision. In addition, any such excess portion would have to be refunded by Phillips to El Paso from the beginning of the refund period in Docket No. G-11217 to the effective date when such excess portion might become legally collectible pursuant to the Sec. 5(a) determination made herein. The terms of the instant Order will accordingly set forth the steps required to accomplish this objective.

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The conclusions expressed above with respect to the effect of the spiral escalation provisions in the Phillips-El Paso contracts are equally applicable to the similar escalation provisions contained in the Phillips-Michigan Wisconsin contracts which are the subject of Docket No. G-10793, and the Phillips-Panhandle contracts which are the subject of Docket No. G-10883. With respect to Docket No. G-10793, involving the sales to Michigan-Wisconsin, it is sufficient to note here that Michigan-Wisconsin makes no contention that the escalation provisions in its contract with Phillips have not yet become operative under their terms. With respect to this general question, Michigan Wisconsin states (p. 6 of initial brief):

> "Michigan Wisconsin has not disputed the reasonableness of price increases which have been required by

[218] See *Phillips Petroleum Co.* v. *F.P.C.*, 227 F. 2d 470 (CCA 10, 1955); and *Kerr-McGee Oil Industries, Inc.* v. *F.P.C.*, (CCA 10, October 24, 1958).

the contracts, and does not propose in this brief to discuss the evidence with respect to the contract increases."

In the case of Docket No .G-10883, involving Phillips' sales to Panhandle, the situation is similar to that already discussed above with respect to the Phillips-El Paso contracts. The Phillips proposed rate increase to Panhandle in this docket is based upon a similar spiral escalation provision in Phillips' Rate Schedule No. 5. Phillips contends that this escalation provision was triggered when Panhandle on January 1, 1955 commenced collecting, subject to refund, higher rates filed by it in its Docket No. G-2506. An initial decision of the Presiding Examiner has been issued in that case on February 10, 1959, and it is presently pending before the Commission on appeal. Under these circumstances, Panhandle contends that Docket No. G-10883 cannot be finally disposed of until the Panhandle resale rates have been ultimately established by final order of the Commission in Docket No. G-2506. Panhandle accordingly contends:

". . . any order issued in the instant proceeding must condition the relief granted Phillips in Docket No. G-10883 upon Phillips' agreement to refund the proportionate amount of the increase per Mcf collected since September 1, 1956, in the event Panhandle is required to make refunds in that proceeding. And, of course, any order in Docket No. G-10883 must be conditioned upon Phillips' filing lower rates as to the future, effective upon the date of final order in Docket No. G-2506, in the event any part of Panhandle's rates are disallowed in that proceeding." (initial brief, p. 9)

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Following the same analysis set forth above with respect to the Phillips-El Paso contracts, it is concluded here that

when Panhandle commenced collecting its proposed G-2506 rates subject to refund, the escalation provision in the Phillips-Panhandle contract became operative *on a tentative basis*, in the sense that the precise amount of the increase triggered by such escalation provision was contingent upon the ultimate resale rate to be finally established by the Commission for Panhandle in that docket. When the Commission ultimately determines the Panhandle rates under Docket No. G-2506, the precise amount of the Phillips increase triggered by such escalation provision will then be established retroactively by relation back to the beginning of the refund period in Docket No. G-10883. The terms of the instant Order will accordingly set forth the steps required to implement these conclusions. It should also be noted that, just as in the case of the Phillips-El Paso contracts, Phillips' rates to Panhandle for the future may be fixed *prospectively* on the basis of the cost of service herein determined for Phillips, pursuant to the Sec. 5(a) procedure already outlined above.

Similarly, it is to be observed that we are here treating the escalation provisions in the Phillips-Michigan Wisconsin contracts and the Phillips-Panhandle contracts solely as the basis for a finding that there was customer consent such as to make the Sec. 4(e) procedure available whether the rates proposed by Phillips in Dockets Nos. G-10793 and G-10883 constitute "just and reasonable" rates, we have been governed exclusively by the cost of service determination made in this decision, and no weight or value whatsoever has been given to the escalation provisions in the Phillips contracts with Michigan-Wisconsin or Panhandle in connection with this determination. Under these circumstances, it is concluded that no further comment is here required with regard to the issues outlined in the Commission's Order of April 26, 1957, with respect to the escalation provisions involved in Dockets Nos. G-11217, G-10793 or G-10883.

XXV. THE OBJECTIVES TO BE ACCOMPLISHED BY THE INSTANT ORDER AND THE STEPS REQUIRED TO IMPLEMENT SUCH OBJECTIVES

Because of the fact that we are here approving a totally different cost of service than that presented by Phillips in this proceeding, it is necessary that rates should now be designed, based upon the approved cost of service, for each of the Phillips jurisdictional rate schedules currently in effect. This should be accomplished by Phillips calculating the given "maximum rate" for gas delivered under the *optimum* conditions, in the manner described above, and by applying the approved rate differentials to such "maximum rate".

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It will then be necessary for Phillips to file with the Commission a list of such *calculated rates*, together with certain necessary data required to explain how such rates were constructed—and the *calculated rates* as thus filed will, of course, be subject to Commission approval.

Section 5(a) of the Natural Gas Act provides:

> "the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company . . ."

However, the Supreme Court in the *Mobile* decision, *supra*, made it clear that

> ". . . if the Commission, after hearing, determines the contract rate to be so low as to conflict with the public interest, it may under Sec. 5(a) *authorize* the natural

gas company to file a schedule increasing the rate." (350 U.S., at page 345, emphasis supplied)[219]

Accordingly, with respect to any existing Phillips rates which are lower than the *calculated rates* which may be filed by Phillips pursuant to the instant Order and which may thereafter be approved by the Commission pursuant to the Sec. 5(a) determination made in this decision, certain additional steps will be required before such higher *calculated rates* can become legally effective, as follows: (1) An Order by the Commission authorizing Phillips to thereafter file rate schedules increasing such existing rates to the level of the approved *calculated rates;* and (2) a subsequent new filing by Phillips under Sec. 4(e) pursuant to such Commission authorization.

Because of the fact that the various Phillips jurisdictional sales involve a number of different types of situations, each requiring somewhat different treatment, it will be helpful at this point to summarize the general objectives which the instant Order is designed to accomplish. It is contemplated that this Order will accomplish the following results:

(1) In the case of Phillips' proposed Sec. 4(e) rates which are lower than the *calculated rates* as subsequently to be approved by the Commission, the proposed Sec. 4(e) rate would constitute the legally effective rate from the beginning of the refund period, and until Phillips, pursuant to the terms of the instant Order, should take the steps required to make the higher *calculated rate* effective prospectively.

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219 To the same effect, see *Interstate Power Company* v. *F.P.C.*, 236 F. 2d 372 (CCA 8, 1956), at p. 378.

(2) However, with respect to Dockets Nos. G-11217 and G-10883, the interim Sec. 4(e) rates applicable to Phillips' sales to El Paso and Panhandle would ultimately be fixed retroactively by relation back to the beginning of the refund period, on the basis of the resale rates finally approved by the Commission for El Paso in Docket No. G-4769 and for Panhandle in Docket No. G-2506.

(3) In the case of Phillips' proposed Sec. 4(e) rates which are higher than the above-mentioned *calculated rates* as approved by the Commission, such Sec. 4(e) rates will be reduced to the level of the *calculated rates*, effective by relation back to the beginning of the refund period, and Phillips would be required to make appropriate refunds on that basis.

(4) In the case of those Phillips jurisdictional rates which are not the subject of a Sec. 4(e) rate filing, and which are higher than the above-mentioned *calculated rates* as approved by the Commission, such rates would be reduced to the level of the mentioned *calculated rates* from and after the date when the said *calculated rates* are approved by the Commission.

(5) In the case of Phillips' jurisdictional rates which are not the subject of a Sec. 4(e) rate filing, and which are lower than the *calculated rates* as approved by the Commission, the filed contract rate will continue to be the legally effective rate until Phillips, pursuant to the terms of the instant Order, may take the steps required to make the higher *calculated rate* effective prospectively.

XXVI—THE EFFECT OF THIS DECISION, IN SUMMARY

As already noted above, the total jurisdictional cost of service herein approved for Phillips amounts to $57,280,218, representing an average unit cost of 11.662 cents per Mcf.

It is also of interest to note again that the Phillips average unit cost as thus determined is reasonably in line with the nation-wide average price of 12 cents per

Mcf paid by interstate pipeline companies for gas purchased directly from independent producers in 1957.[220] This would seem to raise serious doubt as to the validity of the charge frequently made during the past few years that any attempt to apply the cost-of-service or rate-base method to the fixing of producer rates would necessarily produce impossible and ridiculous results.

The $57,280,218 total jurisdictional cost of service and the 11.662 cent per Mcf average unit cost here approved may be compared with the claimed cost of service presented by Phillips in this proceeding in the amount of $92,309,438, representing a claimed average unit cost of 18.793 cents per Mcf, with proposed rates running from 22.75 cents to 16.50 cents depending upon delivery conditions.

The effect of the instant decision, including both the Sec. 4(e) increases herein approved and the additional rate changes which Phillips may obtain pursuant to the Sec. 5(a) procedure outlined herein, would be to provide Phillips with an aggregate rate increase totaling $14 million annually, over and above its jurisdictional revenues prior to the filing of the Sec. 4(e) rate increases involved in this consolidated proceeding. This compares with a $49 million annual increase sought by Phillips. The aggregate increase of $14 million annually, resulting from this decision, would be roughly $8¾ million higher than the $5¼ million increase reflected in Phillips' consolidated Sec. 4(e) dockets—which the interveners have here expressed their willingness to accept.

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220 See report issued by the Commission on November 13, 1958, entitled "Direct Sales By Producers Of Natural Gas to Reporting Interstate Natural Gas Pipeline Companies—1957."

In spite of the large number of seriously controverted issues presented in this proceeding, which have made necessary the lengthy analysis set forth herein, it is interesting to note that the difference of some $35 million between the total cost of service herein approved and that claimed by Phillips results primarily from the difference in treatment of four major issues, as follows:

(1) The income tax component, as to which Phillips' claimed phantom tax allowance is here rejected.

(2) The allowance of a 9.25 percent rate of return, instead of the 12 percent rate proposed by Phillips.

(3) The allocation of exploration costs, as to which the RAR method is here adopted, with a resultant 30.5 percent allocation to gas, instead of Phillips' combined net investment-Btu method which assigns somewhat over 61.8 percent of exploration costs to gas.

(4) The treatment of Phillips' claimed increased purchased gas cost adjustment. The instant decision rejects Phillips' proposed adjustment based upon increased purchased gas costs which it claims will be incurred as a result of the rate increases approved herein. In addition, the royalty and gathering tax adjustments as herein approved are calculated on the basis of a substantially lower total cost of service than that used in the Phillips calculation.

FINDINGS AND CONCLUSIONS

Upon consideration of the entire record in this proceeding, the evidence adduced and the briefs filed, the Presiding Examiner finds and concludes, in addition to the findings and conclusions hereinbefore stated, that

(31651)

(1) The total system-wide jurisdictional cost of service determined for Phillips in this proceeding is $57,280,218, as set forth in Appendix Table 12 hereof.

(2) It is desirable and appropriate that rates should be designed for all of Phillips' jurisdictional sales based upon such system-wide cost of service, and reflecting the delivery condition rate differentials as approved herein, pursuant to the procedure set forth in the order below.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or upon its own motion as provided in the Commission's Rules of Practice and Procedure, that:

(A) Based on the system-wide cost of service herein approved, as set forth in Appendix Table 12 hereof, Phillips shall calculate the "maximum rate for 1,000-pound, sweet, dehydrated, and gathered gas," at such level that its application to the sales volumes delivered in 1954 under each and every one of the 1954 jurisdictional contracts, as adjusted for the approved delivery condition rate differentials, will produce total revenues roughly equal to such system-wide cost of service.

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(B) Within 60 days from the date of issuance of this Order, Phillips shall file with the Commission a statement of such "maximum rate," including a clear and detailed explanation as to the manner in which it was calculated, together with a list of *calculated rates* for all of its jurisdictional rate schedules then in effect. The following information shall be set forth with respect to each such rate schedule: (1) the F.P.C. Rate Schedule number; (2) the name of the purchaser; (3) the delivery point; (4) delivery

pressure, in psig; (5) whether dehydrated or undehydrated; (6) whether sweet or sour; (7) the *calculated rate*, based upon the application of the above-mentioned rate differentials to such "maximum rate."

(C) Upon approval of such *calculated rates* by the Commission, in the case of all rate schedules other than those covered by the proviso below, the *calculated rates* shall immediately become the legally *effective rates for such contracts*, to be observed and in force unless and until changed by subsequent order of the Commission; *provided, however*, that with respect to any such *calculated rates* for sales which are the subject of pending Phillips Sec. 4(e) rate filings, and which are in excess of the Phillips proposed Sec. 4(e) rate, Phillips, after such *calculated rates* are approved by the Commission, will be authorized to file with the Commission new rate schedules increasing such filed Sec. 4(e) rates to the level of the approved *calculated rates*. The same procedure may be followed with respect to any such *calculated rates* affecting a Phillips contract which is not the subject of a pending Phillips Sec. 4(e) rate filing, and where the *calculated rate* exceeds the rate permitted under the terms of the contract. However, in all cases covered by this proviso, until the filing of such new rate schedules by Phillips pursuant to this provision, its legally effective rates for such contracts shall consist of the above-mentioned Sec. 4(e) filed rate, or of the contract rate as the case may be—except that with respect to Dockets Nos. G-11217 and G-10883 herein, the interim Sec. 4(e) rate shall be as determined under the provisions of paragraphs (G) and (H), *infra*.

(D) All jurisdictional contracts hereafter executed by Phillips as seller shall be at rates not exceeding the above-mentioned "maximum rate," adjusted by such delivery con-

dition rate differentials, as approved by the Commission, until further order of the Commission.

(E) With respect to all those Phillips Sec. 4(e) rate filings which are consolidated with the instant proceeding, and under which Phillips, subject to a refund undertaking, has been collecting rates higher than such *calculated rates* as approved by the Commission, Phillips will be required to make appropriate refunds, as determined and directed in a subsequent order to be issued by the Commission.

(F) With respect to all those Phillips Sec. 4(e) rate filings which are consolidated with the instant proceeding, and under which Phillips, subject to refund undertaking, has been collecting rates not in excess of the *calculated rates* as approved by the Commission, such Sec. 4(e) proceedings will thereafter be ordered terminated and Phillips will thereupon be relieved of any obligation to make refunds thereunder—with the exception of the Phillips Sec. 4(e) rate filings in Dockets Nos. G-11217 and G-10883, as to which special provision is set forth in paragraphs (G) and (H) below.

(G) Upon the issuance of a final Commission decision in El Paso's pending Sec. 4(e) rate proceeding in Docket No. G-4769, Phillips shall file with the Commission a Motion Requesting Termination of its Sec. 4(e) proceeding in Docket No. G-11217. A determination will thereupon be made of the appropriate Phillips Sec. 4(e) rate in Docket No. G-11217, based upon the rate increase ultimately approved for El Paso in Docket No. G-4769, but in no event to exceed the above-mentioned *calculated rate* as approved by the Commission for such Phillips-El Paso sale. The Phillips Sec. 4(e) proceeding in Docket No. G-11217 will then be ordered terminated, subject to such appropriate refund order, if any, as may be warranted in the event that El

Paso's proposed Sec. 4(e) rate increase in Docket No. G-4769 may not have been approved *in toto.*

(H) Upon the issuance of a final Commission decision in Panhandle's pending Sec. 4(e) rate proceeding in Docket No. G-2506, Phillips shall file with the Commission a Motion Requesting Termination of its Sec. 4(e) proceeding in Docket No. G-10883. A determination will thereupon be made of the appropriate Phillips Sec. 4(e) rate in Docket No. G-10883, based upon the rate increase ultimately approved

for Panhandle in Docket No. G-2506, but in no event to exceed the above-mentioned *calculated rate* as approved by the Commission for such Phillips-Panhandle sale. The Phillips Sec. 4(e) proceeding in Docket No. G-10883 will then be ordered terminated, subject to such appropriate refund order, if any, as may be warranted in the event that Panhandle's proposed Sec. 4(e) rate increase in Docket No. G-2506 may not have been approved *in toto.*

JOSEPH ZWERDLING
Presiding Examiner

31766

PHILLIPS PETROLEUM COMPANY

BARTLESVILLE, OKLAHOMA

May 28, 1959

Mr. J. H. Gutride, Secretary
Federal Power Commission
441 'G' Street, N. W.
Washington 25, D. C.

Re: In the Matter of Phillips Petroleum Company, Docket No. G-1148, et al.

Dear Sir:

By Motion served April 16, 1959, Northern Natural Gas Company and Permian Basin Pipeline Company requested that the Commission enter an order in this proceeding requiring that Phillips Petroleum Company, without prejudice to Phillips' rights, make known to Northern and Permian the "calculated rates" which Phillips would be required to file under the Examiner's decision in this proceeding, for sales of gas to Northern and Permian. Subsequently, Southern California Gas Company, Southern Counties Gas Company, Pacific Gas and Electric Company and San Diego Gas and Electric Company filed motions seeking similar information and, in addition, a comparison of such "calculated rates" with the actual rates in effect on April 1, 1959, together with the 1958 volumes applicable thereto. The motions request that such information be furnished not later than May 15, 1959.

All of these motions together would, in effect, require that Phillips now comply fully with the Examiner's decision in this proceeding, that it furnish additional information not required by the Examiner, and that all of this be done in little more than half the time permitted by the Ex-

aminer's decision. We think it is apparent that this is not a reasonable request. The information required to formulate the "calculated rates" in the exactness required by paragraphs (A) and (B) is not readily available even to Phillips. Paragraphs (A) and (B) differ substantially from the rate recommendations made by Phillips during the hearing. Among other things, these paragraphs would require that "calculated rates" be

filed with respect to contracts considered *de minimis* by Phillips and for which no change in contract rate was proposed. Since many of these sales are from individual wells in which Phillips is only a small interest owner and the non-operator, the information with respect to delivery conditions (necessary for the application of the required rate differentials), is not maintained in Phillips' files and would have to be obtained from the various operators.

We recognize, however, that these requests were made in an effort to appraise the effects of the Examiner's decision and that information which may be most readily available to Phillips would be of material assistance to the other parties to the proceeding. We believe that approximate rates applied to Phillips' major sales only will provide all of the information which these parties may desire or find useful and at the same time will avoid placing undue burden upon Phillips.

We have calculated that the "maximum rate" referred to in paragraph (A) of the Examiner's decision would, under all of the conditions of the Examiner's decision, be approximately 15¢ per Mcf at 14.65 psia. In determining this approximate "maximum rate" we have not attempted to establish rates for all of Phillips' sales, as the Examiner's decision would require. We have not determined the "calculated rate" for any sale for which no rate was recom-

mended by Phillips in Exhibits 324 and 357, but in determining the "calculated rates" for other sales we have taken into acount the revenues at contract rates for sales under percentage-type casinghead gas contracts and sales which were considered by Phillips as *de minimis*. As previously indicated, determination of "calculated rates" for casinghead gas and *de minimis* sales would substantially increase the time and effort required to furnish this information. The total volume of all such sales is so small that it does not appear that the income from such sales would have any substantial effect upon the "maximum rate".

We are attaching hereto a schedule listing each of Phillips' rate schedules shown on Exhibit 357 (which constitutes the major sales of Phillips in effect during the hearing) showing the price actually in effect on April 1, 1959, the volumes delivered in 1958, and the "calculated rate" which would be applicable to each such sale. Volumes are shown on the same basis as in said exhibits. By a comparison of the volumes and prices shown on this schedule with the volumes and prices shown correspondingly for each rate schedule on Exhibits 324 and 357, we believe it will be possible for any Intervenor to make its own computation of the impact which the decision would have upon it.

It should be clearly understood that this information is being furnished merely as an assistance to the Intervenors and is without prejudice to any position which Phillips may take with respect to the Examiner's decision. Specifically, by furnishing this information Phillips does not agree that any particular action is required of Phillips by the terms of the Examiner's decision or admit that the decision is applicable to any particular sale. Moreover, the "maximum rate" of 15¢ per Mcf

is based upon an average rate of 11.662¢ per Mcf as determined in the Examiner's decision. Phillips believes that,

for reasons which will be stated in formal exceptions to the Examiner's decision which will be filed, this average rate of 11.662¢ per Mcf is incorrect and should be increased. If this average rate is ultimately determined to be higher than 11.662¢ per Mcf, then correspondingly, the "maximum rate" will be higher than 15¢ per Mcf and each of the "calculated rates" will likewise be higher.

A copy of this letter and the attached schedule are being sent to each party of record.

Respectfully submitted,

By /s/ KENNETH HEADY
Kenneth Heady
Attorney
Phillips Petroleum Company

KH:rb
Attachment

PHILLIPS PETROLEUM COMPANY & SUBSIDIARIES
1958 VOLUMES, APRIL 1 1959 RATES & RATES COMPUTED ON BASIS OF EXAMINER'S COST OF SERVICE FOR RATE SCHEDULES LISTED ON EXHIBIT 357

F.P.C. RS No.	Purchaser	Source of Gas	1958 Volume Mcf @ 14.65	Rates @ 14.65 Psia April 1, 1959 Approved for Collection (A)	Rates @ 14.65 Psia Computed from Examiner's Cost of Service
1-A	United Gas P. L. Co.	Wellhead	137,268	6.615c	13.75c
2-A	Texas Eastern Trans. Corp.	Wellhead	2,614,266	13.920c	12.80c
3	Tennessee Gas Trans.	System	101,867	12.123c	15.00c
4	Michigan-Wisconsin P. L.	Sherman Plant—Stratford	21,707,813	11.473c	12.75c
		Sherman Plant—Okla.	6,627,774	11.405c	12.75c
		Sherman Plant—Texas	86,870,811	11.522c	12.75c
5	Panhandle Eastern P. L. Co.	Hansford Plant—Texas	14,520,016	6.967c	13.00c
		Hansford Plant—Okla.	12,960,710	6.889c	13.00c
		Sneed Plant	21,338,452	6.967c	12.75c
7	El Paso Natural Gas Co.	Goldsmith Plant	5,320,829	10.255c	10.25c
9	El Paso Natural Gas Co.	Crane Plant	9,706,586	8.335c*	10.00c
10	El Paso Natural Gas Co.	Keystone Plant	1,750,555	10.446c	13.25c
13	United Gas P. L. Co.	Wellhead	3,162,996	9.622c	13.15c

* Contract rate of 9.934c adjusted to volume shown.

** Pipeline Volume.

RS No. F.P.C.	Purchaser	Source of Gas	1958 Volume Mcf @ 14.65	Rates @ 14.65 psia April 1, 1959 Approved for Collection (A)	Computed from Examiner's Cost of Service
18	Permian Basin P. L. Co.	Benedum Plant	1,447,596	11.066c	11.00c
		Andrews Plant	23,617,836	11.066c	11.00c
		Spraberry Plant	7,143,585	11.066c	11.00c
		Pembrook Plant	24,341,040	11.060c	11.00c
		Wellhead—Devonian	8,858,071	15.144c	13.15c
		Wellhead—Ellenberger	24,948,718**	10.096c	8.15c
19	Consolidated Gas Util. Co.	Lefors Plant	12,217,284	13.673c	13.15c
20	Tennessee Gas Trans. Co.	Wellhead	25,294	11.903c	13.15c
21	Colorado Interstate Gas Co.	Sanford Plant	14,402,045	16.154c	11.60c
23	Texas Gas Trans. Corp.	Carthage Plant	860,073	10.610c	14.25c
24	Northern Natural Gas	Dumas Plant	14,371,229	13.940c	12.75c
27	Texas-Ill. Nat. Gas P. L.	Chocolate Bayou Plant	10,834,772	10.449c	15.00c
31	Arkansas-Louisiana Gas	Wellhead	342,536	11.505c	12.45c
32	El Paso Natural Gas	Goldsmith Plant	24,526,443	10.255c	10.25c
		Eunice Plant	12,603,052	10.170c	10.25c
		Fullerton Plant	5,059,322	10.255c	10.25c
		Dumas Plant	39,282,152	13.528c	12.75c
		31770			
33	El Paso Natural Gas Co.	Goldsmith Plant	20,052,764	10.255c	10.25c
34	Tennessee Gas Trans.	Wellhead	80,079	13.278c	13.75c
39	Tennessee Gas Trans.	Wellhead	68,831	13.498c	14.00c
41	Texas-Illinois Nat. Gas	Chocolate Bayou Plant	2,338,591	15.811c	15.00c
42	Texas Gas Corp.	Wellhead	131,760	11.106c	13.75c

(31770)

RS No. F.P.C.	Purchaser	Source of Gas	1958 Volume Mcf @ 14.65	Rates @ 14.65 psia April 1, 1959 Approved for Collection (A)	Computed from Examiner's Cost of Service
47	El Paso Natural Gas Co.	Wellhead	381,432	10.601c	13.15c
48	Arkansas-La. Gas Co.	Wellhead	266,567	12.240c	14.75c
52	Panhandle Eastern P. L. Co.	Wellhead	205,183	2.233c	9.50c
59	Permian Basin P. L.	Wellhead	569,654	9.500c	12.05c
61	Panhandle Eastern P. L. Co.	Wellhead	5,734,647	3.910c	9.50c
64	El Paso Natural Gas Co.	Eunice Plant	13,751,895	10.170c	10.25c
65	El Paso Natural Gas Co.	Wellhead	687,140	10.500c	12.05c
66	El Paso Natural Gas Co.	Denton Plant	342,775	11.509c	14.50c
68	Cities Service Gas Co.	Edmond Plant	1,377,538	7.603c	14.00c
69	Cities Service Gas Co.	Hunton & Trindle Plants	329,413	6.700c	14.00c
82	Shamrock Oil & Gas Corp.	Wellhead	139,748	8.500c	9.10c
140	Breckenridge Gasoline Co.	Wellhead	148,086	7.542c	12.80c
143	Panhandle Eastern P. L. Co.	Wellhead	239,106	3.127c	9.50c
145	Texas Gas P. L. Co.	Wellhead	940,477	12.731c	13.15c
148	Ryeade Oil Corp.	Wellhead	61,416	7.00 c	10.35c
149	Transcontinental Gas P. L. Co.	System	805,562	17.063c	14.50c
150	Consolidated Gas Util. Corp.	Wellhead	263,275	11.00 c	10.75c
175	Southern Natural Gas Co.	System	1,139,280	14.123c	15.00c
187	Tennessee Gas Trans. Co.	System	Cancelled		
188	El Paso Natural Gas Co.	Wellhead	Rejected		
202	Texas Northern Gas Corp.	Wellhead	343,335	20.291c	14.00c
209	Tennessee Gas Trans. Co.	Wellhead	549,011	13.278c	13.75c
216	United Gas P. L. Co.	Wellhead	266,913	6.445c	12.80c
217	United Gas P. L. Co.	Wellhead	Withdrawn		

RS No. F.P.C.	Purchaser	Source of Gas	1958 Volume Mcf @ 14.65	Rates @ 14.65 psia April 1, 1959 Approved for Collection (A)	Rates @ 14.65 psia Computed from Examiner's Cost of Service
218	Tennessee Gas Trans. Co.	Wellhead	664,778	21.288c	14.00c
219	Southern Natural Gas Co.	System	3,841,480	21.450c	14.50c
220	Transcontinental Gas P. L. Co.	Wellhead	507,072	17.063c	13.75c
229	Northern Utilities Co.	Wellhead	Withdrawn		
231	Tennessee Gas Trans. Co.	Wellhead	180,777	13.278c	13.75c
239	Miss. River Fuel Corp.	Hico Knowles Plant	391,576	12.922c	15.00c
243	El Paso Natural Gas Co.	Lee Plant	4,223,440	10.805c	12.00c
		Hobbs Plant	7,050,487	10.170c	10.25c
		31771			
252	Northern Nat. Gas Co.	Wellhead	657,434	13.083c	12.80c
262	Northern Nat. Gas Co.	Gray Plant	17,679,856	13.630c	11.00c
270	Panhandle Eastern P. L. Co.	Wellhead	658,282	10.000c	9.50c
273	United Fuel Gas Co.	Erath Plant	7,965,143	21.743c	15.00c
		No. Erath & Erath Shallow	6,603,518	21.743c	15.00c
274	El Paso Nat. Gas Co.	Wellhead	231,249	10.500c	12.40c
276	Louisiana Nevada Transit Co.	Wellhead	48,752	11.700c	12.45c
278	American Louisiana P. L. Co.	System—Bourque Unit	525,697	20.963c	14.75c
279	Pacific Northwest P. L. Corp.	Wellhead	497,422	18.038c	12.45c
W.E.#1	Cities Service Gas Co.	Hunton & Trindle Plant	37,906	6.700c	14.00c
W.E.#2	Cities Service Gas Co.	Edmond Plant	132,140	7.603c	14.00c

(A) Includes tax reimbursement.

RLH:amp
5-6-59

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(31771)

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31855

Order Denying Motion

(Issued July 17, 1959)

On June 25, 1959, El Paso Natural Gas Company (El Paso) filed a motion requesting that the Commission require Phillips Petroleum Company (Phillips) to comply fully with the Presiding Examiner's decision issued herein on April 6, 1959 and to extend the time for filing of exceptions to said examiner's decision for a period of 30 days from the date on which said compliance is made. In its motion, El Paso cited paragraphs (A) and (B) as set forth at pages 314-315 of the aforementioned decision and stated, among other things, that, while such paragraphs unequivocally require Phillips to submit data respecting both the "maximum rate" and the "calculated rates" within 60 days following the issuance of such decision, Phillips has not complied therewith. El Paso also states that Phillips, by letter dated May 28, 1959, submitted to the Commission certain data and information which apparently is intended to satisfy requests contained in certain motions [1] for Phillips to calculate and publicize the rates which it would propose to place in effect if such decision were to be adopted by the Commission as well as to comply with the provisions of said paragraphs (A) and (B). El Paso asserted that Phillips submittal suggests a "maximum rate" as required

[1] On April 17, 1959, Northern Natural Gas Company and Permian Basin Pipeline Company filed a motion with the Commission, requesting, *inter alia*, that Phillips make known to those companies the "calculated rates" required by the Examiner's Decision for sales of natural gas under all contracts which Phillips has with those companies. Subsequently, Southern California Gas Company, Southern Counties Gas Company of California, Pacific Gas & Electric Company and San Diego Gas and Electric Company filed motions with the Commission seeking similar information and, additionally, a comparison of the "calculated rates" with the actual rates in effect on April 1, 1959, together with the volumes for the year 1958 applicable thereto.

by said paragraph (A) of "approximately 15¢ per Mcf at 14.65 psia" and lists "calculated rates" for only a portion of

Dockets Nos. G-1148, *et al.*

Panhandle Eastern Pipe Line Company on July 2, 1959, and Phillips on July 6, 1959, filed answers to El Paso's motion stating, in effect, that (1) Phillips, by its letter of May 28, 1959, furnished to all parties a statement of the approximate calculated rates applicable to the rate schedules which account for more than 95% of its jurisdictional gas sales volume and advised the Commission that some of the information which would be needed "is not readily available, even to Phillips"; (2) that the Presiding Examiner has not attempted to require Phillips to submit such data; (3) that said paragraphs (A) and (B) are clearly contingent upon the Commission's prior adoption of the Examiner's conclusion in that the introductory portion of the proposed order (p. 314) states that it is "subject to review by the Commission on appeal"; and (4) that, inasmuch as the Secretary of the Commission extended the time for filing exceptions herein to and including July 27, 1959, the said decision is not final. In addition, Phillips stated (1) that it had received no indication that the said furnished information was not fully satisfactory to the parties who requested it; (2) that representatives of the Eastern Seaboard Intervenors, the Southern California Companies, and Panhandle Eastern Pipe Line Company have in informal discussions indicated their satisfaction with the material furnished;[2] and (3) that as El Paso did not originally request the information, that "under these circumstances it is apparent that El Paso's motion can have no basis except delay."

[2] Northern Natural Gas Company and the Southern California Companies have so advised the Commission.

Inasmuch as the Presiding Examiner's decision herein is still subject to review by the Commission on appeal or upon its own motion as provided in the Commission's Rules of Practice and Procedure, it is considered that, at this time, the delay necessitated in effecting El Paso's request would not be warranted.

The Commission finds:

Good cause has not been shown for granting El Paso's request.

The Commission orders:

El Paso Natural Gas Company's motion filed June 25, 1959 is denied.

By the Commission.

32397

Exceptions By the Public Utilities Commission of the State of California to Intermediate Decision.

Comes now the Public Utilities Commission of the State of California (California) and pursuant to Section 1.31 of the Rules of Practice and Procedure of the Federal Power Commission, does hereby appeal to the Commission from and files exceptions to the decision of the Presiding Examiner in the above-entitled matter filed on April 6, 1959.

INTRODUCTION AND COMMENT.

The Zwerdling decision is the first step toward producer regulation based upon conventional utility type cost of service theories. In general, California supports the Examiner's decision particularly against those expected criticisms that its allowances to Phillips are unrealistic and conservative. Insofar as the decision attempts to fix just and reasonable prices through the vehicle of cost of service approach, California supports it save for the exceptions hereinafter set forth.

EXCEPTION No. I

A. California excepts to the following portion of the Decision appearing at pages 294-5:

> "After considering all of the matters outlined above, it is here concluded that the system-wide rate approach represents a satisfactory and appropriate method for the fixing of 'just and reasonable' producer rates, for the following reasons:

"(1) It is inherently simple to administer.

"(2) It would be fair to the producer, in the sense that it permits him to recover his total cost of service in one way or another.

"(3) It would eliminate unreasonable preferences currently enjoyed by pipelines which are still purchasing gas under old, abnormally low-priced contracts—preferences which are based not merely upon differences in cost levels, but which reflect other historic reasons.

"(4) Although the effect of a system-wide rate would be that pipelines such as Panhandle and El Paso, which are presently enjoying abnormally low prices under certain old, long-term gas supply contracts, should be required to pay a higher price level under such contracts, this would be only a short-term, temporary disadvantage. Furthermore, any such temporary disadvantage would be counterbalanced by the fact that their necessary purchases of additional gas reserves from more recently developed and higher-cost areas would be made at lower rates than would have resulted under an area-pricing method."

SUPPORTING REASONS

The system-wide uniform rate which the decision employs results in the postage stamp type of rate. Such a rate ignores relationship between costs and revenues. It ignores the fundamental principle of rate making that the ratepayer should pay only for the service benefits furnished them. It ignores the differences between customers of Phillips and the facilities which serve them. It does not take into consideration the variety of production costs as they exist between different supply areas.

Natural Gas Act, Sec. 4(b)
Transcript, Vol. 96, p. 12,787
Transcript, Vol. 101, p. 13,345
Transcript, Vol. 101, p. 13,399
Transcript, Vol. 101, p. 13,401

32399

PROPOSAL

California proposes the deletion of those portions of the Examiner's opinion to which exceptions are taken. In lieu of such deleted portions, California proposes the following: "The system-wide rate approach or the so-called postage stamp type of rate is neither suitable to nor required by all of the sales of natural gas by Phillips. A single over-all rate is not proper because it would result in undue preferences contrary to the Natural Gas Act. Consumers should be required to pay only their proper and reasonable portion of the expense of gas purchases devoted to their needs. An area cost of production should be adopted based upon the record herein."

EXCEPTION NO. II

California excepts to that portion of the decision wherein a 9.25 percent rate of return is allowed.

SUPPORTING REASONS

Natural Gas Act, Section No. 4(a)

Phillips is a corporation operating within a regulated industry. It is committed by law to rendering charges at the lowest reasonable rates.

State of Missouri ex rel Southwestern Bell Telephone Company, plf. in Error vs. Public Service Commission of Missouri, et al., 262 U.S. 276.

(32399)

The record shows that the Witness Colbert testifying on behalf of Wisconsin presented testimony and evidence supporting an over-all rate of return of 7.75 per cent. This in itself is somewhat beyond the usual rate of return. However, the Commission should adopt this rather than the Zwerdling figures.

32400

PROPOSAL

California proposes the deletions of those portions of the Examiner's opinion permitting a rate of return of 9.25 percent and would substitute in lieu thereof the following language:

"Phillips' rate of return herein based upon the evidence received should not be in excess of 7.75 percent."

EXCEPTION No. III

California excepts to the omission in the decision of a finding that Phillips' spiral escalation clauses are contrary to the public interest and void for regulatory purposes under the Natural Gas Act.

SUPPORTING REASONS

Phillips is now a regulated producer. This Commission by law may only recognize actual costs as the basis for any present or future rate increases.

PROPOSAL

California proposes in lieu thereof: "Those spiral escalation provisions existent in Phillips' contracts with its purchasers are contrary to the Natural Gas Act and will not be recognized by this Commission as the basis for

proposed or requested increased rates absent the occurrence of actual reasonable cost."

Respectfully submitted,

/s/ WILLIAM M. BENNETT
William M. Bennett
Chief Counsel

/s/ RODERICK B. CASSIDY
Roderick B. Cassidy
Assistant Chief Counsel
Attorneys for the People of the State of California and the Public Utilities Commission of said State
514 State Building
San Francisco, California

Dated: July 31, 1959

* * * * * * * * * * *

32539

PHILLIPS PETROLEUM COMPANY

Bartlesville, Oklahoma

April 6, 1960

Offer of Settlement —
Docket No. G-1148, et al.

Federal Power Commission
441 G Street, Northwest
Washington 25, D. C.

Gentlemen:

Nearly twelve years ago, the Federal Power Commission first instituted the proceeding in Docket No. G-1148. Since then, the Commission has found that Phillips was not a natural gas company within the meaning of the Natural Gas Act, was reversed by the Supreme Court on that ruling, held lengthy hearings under Section 5(a) of the

Natural Gas Act commencing in June, 1956, and, in October, 1959, heard oral arguments on exceptions to the Examiner's decision. Phillips—indeed, the entire natural gas industry—has been operating for a long time in a state of indecision and confusion.

During the hearings under Section 5(a), the Federal Power Commission Staff, Phillips, and numerous intervenors presented various costs of service and various methods of setting or changing rates in order to produce some specific cost of service. Phillips' calculation of its cost of service for the test year of 1954 was $92.3 million, as compared with revenues as of late 1956 of $48.3 million. Every cost of service offered by the Staff and intervenors (there were 63 pipelines, distributors, state commissions and municipal bodies permitted to intervene in the proceedings), regardless of how computed, exceeded Phillips' revenues—the only question was the degree. The method of fixing rates to return the cost of service (whatever it might be) was the subject on which there was the greatest lack of agreement.

During and since the hearing, Phillips' rates for many of those sales involved in the 1954 test year have been increased, both by contractual provisions and by renegotiation of contracts providing, among other things, for the removal of indefinite pricing provisions. As a result, Phillips, although it is not yet recovering its true cost of service, has reduced its deficiency materially. Phillips does not recede from its position that the the $92 million cost of service which it put in evidence in Docket No. G-1148 is its true cost of service, or that it is entitled to recover that cost of service from its jurisdictional sales. However, considering the almost endless confusion and delay (and possible serious economic consequences for certain of Phillips' customers) which would ensue were the Commis-

sion to attempt, by *any* method, to determine new prices for

each of Phillips' contracts which, in the aggregate, would return Phillips', or any other, cost of service, Phillips hereby makes the following offer of settlement. Such settlement offer is based entirely on the prices contracted between Phillips and its purchasers, and for the purposes of this settlement, Phillips waives its right to higher rates which would return to it its true cost of service. Specifically, Phillips offers to settle the proceedings involved in Docket No. G-1148, et al. on the following basis:

1. With respect to those rate schedules included in Docket No. G-1148, et al., the contract prices as of the date of the Commission's order would be approved.

2. With respect to those rate schedules included in Docket No. G-1148, et al., all price increases now being collected subject to refund would be approved and the proceedings terminated without refund.

3. Such new rates as may be ultimately agreed upon under rate schedules 4 and 19 (subject to the limitation shown in Schedule II attached hereto), which are now being renegotiated, would be approved as of such time as the amended rate schedules are filed with the Commission.

4. The Commission would terminate without refund all Section 4(e) proceedings involving rate schedules not included in Item 1 above.

Phillips is induced to make this offer for the following reasons:

1. Any system or method of determining individual rates to meet a specific cost of service would undoubtedly be assailed in the courts by practically all parties, thus even further prolonging a final decision in the matter. On the other hand, by approving the prices agreed to by contract with our pipeline purchasers, at least the objections of that group of intervenor-protestants would be eliminated, since

it is a reasonable assumption that such purchasers would not challenge prices under contracts which they have voluntarily entered into.

2. The elimination of the problem of determining specific individual rates (188 separate rate schedules) will permit an earlier conclusion to this proceeding, which will be of great benefit to the Commission, its Staff, and all segments of the natural gas industry.

3. The uncertainties with respect to natural gas prices at the producer and consumer level growing out of this proceeding which has been pending nearly six years will be eliminated.

4. Regardless of the circumstances, almost every rate increase filed by Phillips since June 7, 1954, has been suspended and is being collected subject to refund. The amounts so collected are substantial and are increasing each month. If allowed to continue, Phillips' exploratory program may be adversely affected.

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As shown in the attached schedules I through IV, the annual revenue to Phillips at April 1, 1960 contract prices, from the contracts which were the subject of the hearing in Docket No. G-1148, et al. (subject to notations in the attached schedules as to specific prices now being renegotiated) amounts to $70.8 million. These prices are amply justified by its cost of service of $92.3 million and by the Examiner's cost of service when it is adjusted for its obvious errors with respect to statutory tax allowances and increased gas purchase costs, and for appropriate adjustments to the allowance for exploration. With respect to the Section 4(e) proceedings referred to in Item 4 on Page 2, which are not directly subject to these proceedings, a comparison of the contract prices in those proceedings

with contract prices in Item 1 on Page 2 amply supports the termination of such Section 4(e) proceedings. The attached Schedule V shows both Phillips' and the Examiner's costs of service, together with a series of costs of service reflecting various adjustments.

RBS:omr
Enclosures

Very truly yours,

R. B. STEWART
R. B. Stewart, Vice President
Natural Gas Department

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SCHEDULE I

SUMMARY OF REVENUES AT APRIL 1, 1960 CONTRACT PRICES UNDER RATE SCHEDULES INCLUDED IN EXHIBITS 288 AND 289 OF G-1148

Type	1954 Volumes, Mcf @ 14.65	Revenues April 1, 1960 Contract Prices, Dollars
Rate schedules under which deliveries were made in 1954 and which are still in effect on April 1, 1960 (see SCHEDULE II).	431,481,254	$64,298,993
Rate schedules under which deliveries were made in 1954, but which have been terminated as of April 1, 1960 (see SCHEDULE III).	38,934,240	5,075,447
Deliveries under casinghead-type contracts which had been filed as rate schedules (See SCHEDULE IV).	20,716,526	1,463,009
Exchange (R.S. 212)	46,933	4,693
TOTAL	491,178,953	$70,842,142

SCHEDULE H

REVENUES FROM RATE SCHEDULES
LISTED IN EXHIBITS 288 AND 289 OF G-1148
STILL IN EFFECT AS OF APRIL 1, 1960

Rate Schedule Number	April 1, 1960 Contract Price* ¢/Mcf @ 14.65	Indicated Revenue, Dollars	1954 Volume Mcf @ 14.65
1-A	6.6806	87,858	5,869
2-A	14.8000	2,477,038	366,602
3	17.2435	165,333	28,509
4	16.5000**	126,671,655	20,900,823
5	13.0000	52,531,706	6,829,122
6	9.5861	28,798	2,759
7	13.6175	122,560	16,687
9 (8)	13.3632	7,355,245	982,896
10	16.1286 (a)	2,054,887	331,425
13	9.6216	3,047,243	293,194
17	10.6722	76,781	8,194
18 (Plants)	11.0661	26,853,264	2,971,609
(Puckett)	11.1056 (b)	5,862,642	—
	P. L. Volume	(3,693,992)	410,240
19	17.0000**	12,155,597	2,066,451
20	17.0242	275,340	46,874
21	17.1632	14,565,740	2,499,947
22	14.1344	40,923	5,784
23	10.6105	809,060	85,845
27	10.8951	10,220,000	1,113,479
29	15.3333	61,583	9,443
30	17.2435	65,492	11,293
31	11.5055	714,458	82,202
32 (Goldsmith)	13.6155	25,600,659	3,485,658
(Eunice)	3.5330	12,433,435	1,682,617
(Fullerton)	13.6155	5,889,576	801,895
(Dumas)	19.7632	38,780,996	7,664,366
33	13.6155	8,577,295	1,167,842
34	15.9502	183,328	29,241
36	15.9502	107,581	17,159
37	8.8733 (c)	53,709	4,766
38	7.4950 (d)	22,482	1,685
39	16.1695	167,488	27,082
40	15.2025	122,481	18,620
41	15.8106	6,503,518	1,028,245

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Rate Schedule Number	April 1, 1960 Contract Price* ¢/Mcf @ 14.65	Indicated Revenue, Dollars	1954 Volume Mcf @ 14.65
42	9.0864(e)	150,976	13,718
43	17.0242	47,430	8,075
47	15.7092	1,292	203
48	12.2410	20,839	2,551
53	9.0397	12,219	1,105
56	7.4561	120,549	8,988
57	16.0000	13,885	2,222
58	8.0512	29,948	2,411
59	10.766	408,304	43,969
	32544		
60	7.5000	99,173	7,438
62	12.5007	107,924	13,491
63	8.9808	278,014	24,968
64	13.5330	13,476,859	1,823,823
65	15.5598	505,830	78,706
66	17.0436	251,808	42,917
68	7.5930	6,477,720	491,853
69	6.6997	1,282,711	85,938
81	9.0000	54,131	4,872
83	8.5000	226,468	19,250
140	6.0424(f)	255,633	15,446
144	3.7965	422,455	16,039
148	7.0000	180,697	12,649
150	11.0000	185,466	20,401
151	15.1131	54,160	8,185
158	11.0000	26,291	2,892
175	14.1240	1,370,081	193,510
183	11.7518	108,068	12,700
189	10.9626	102,037	11,186
200	15.9502	118,274	18,865
202	20.1916	301,220	61,122
209	15.9502	192,035	30,630
216	20.2916	285,023	57,836
218	22.2634	331,990	73,912
219	23.0841	1,097,355	253,315
220	22.9622	513,047	117,807
231	15.9502	243,943	38,909
239	12.9225	470,339	60,780
241	9.7229	10,196	991
243 (Lee)	14.0343	3,342,639	469,116
(Hobbs)	13.5330	5,820,272	787,657

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Rate Schedule Number	April 1, 1960 Contract Price* ¢/Mcf @ 14.65	Indicated Revenue, Dollars	1954 Volume Mcf @ 14.65
258 (214)	6.5000	143,072	9,300
262 (26, 28)	18.9300	17,914,056	3,391,131
310 (242)	7.8003	4,133	322
323 (70)	13.3000	6,036	803
324 (159)	13.3000	7,518	1,000
356 (52, 61, 143, 270)	10.0000	9,164,854	916,485
W.E. #1	6.6997	148,459	9,946
W.E. #2	7.5930	410,074	31,137
TOTAL		431,481,254	$64,298,993

(See footnotes on following page.)

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FOOTNOTES

*Contract price shown includes tax reimbursement, but is after certain deductions by the purchaser as indicated by the footnotes below:

(a) After deduction of 1.0¢ per Mcf for sour, undehydrated gas.
(b) After deduction of 5.0¢ per Mcf for treating.
(c) After deduction of 5.0¢ per Mcf for compression.
(d) After deduction of 0.5¢ per Mcf for gathering.
(e) After deduction of 2.0¢ per Mcf for compression.
(f) After deduction of 1.5¢ per Mcf for compression.

**The prices shown are not the current contract prices. Phillips is renegotiating these contracts and the prices shown here are the maximum prices being considered in these negotiations.

SCHEDULE III

REVENUES FROM RATE SCHEDULES LISTED IN EXHIBITS 288 AND 289 OF G-1148 UNDER WHICH DELIVERIES HAVE BEEN TERMINATED AS OF APRIL 1, 1960

Rate Schedule Number	Contract Price at Date* of Termination ¢/Mcf	1954 Volume Mcf @ 14.65	Indicated Revenue, Dollars	Certificate Docket No.	Abandonment Docket No.	Rate Schedules Rejected or Withdrawn
24	14.4443	18,541,588	$2,678,203	G-2620	G-18113	
25	10.7187	25,063	2,686	2615		Yes
35	13.1870	128,163	16,901	2608		Yes
55	7.0250	124,626	8,755	3338		Yes
77	5.5000	101,237	5,568	3369	10054	
78	5.5000	95,814	5,270	3370	10055	
82	14.0000	12,890,127	1,804,618	3897	11686	
152	7.5000	140,130	10,510	3440		Yes
157	11.0000	93,705	10,308	3444	18524	
169	4.1295	11,321	468	3501		Yes
181	3.7283	2,385,293	88,931	4179		Yes
186	11.7000	17,715	2,073	3471		Yes
187	9.9707	1,550,144	154,560	3824		Yes
188	10.5000	184,002	19,320	3472		Yes
192	4.7846	97,166	4,649	3476	8893	
193	4.7762	55,268	2,640	3477	8893	
194	4.5115	50,951	2,299	3478	8893	
197	11.7000	155,942	18,245	3471		Yes
198	10.7250	20,329	2,180	3471		Yes
217	10.2352	844,010	86,386	3497		Yes
222	2.6332	100,690	2,651	3505	8756	
228	11.7000	118,403	13,853	3471		Yes
229	7.8000	161,534	12,600	3511		Yes
230	11.7000	956,951	111,963	3471		Yes
232	11.7000	4,169	488	3471		Yes
233	11.7000	40,994	4,796	3471		Yes
235	11.7000	18,857	2,206	3471		Yes
236	10.7250	1,228	132	3471		Yes
237	10.7250	1,431	153	3471		Yes
248	11.7000	17,389	2,035	3471		Yes
TOTAL		38,934,240	$5,075,447			

*Contract price shown includes tax reimbursement. Rate schedules 192, 193, and 194 were percentage type casinghead contracts and the prices shown are average unit revenues based on the last year's deliveries.

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SCHEDULE IV

REVENUES UNDER CASINGHEAD-TYPE CONTRACTS
FILED AS RATE SCHEDULES AND INCLUDED
IN EXHIBIT 288 OF G-1148

Rate Schedule Number	1954 Volume Mcf @ 14.65	1958 Unit Revenue* ¢/Mcf @ 14.65	Indicated Revenue, Dollars
16	18,900	4.8593	918
44	42,687	6.1291	2,616
46	29,351	5.0130	1,471
49	5,235	11.9617	626
51	91,890	2.5269	2,322
67	219,405	4.0739	8,938
71	96,047	12.5932	12,095
72	59,399	10.0227	5,953
73	45,488	8.7502	3,980
74	21,002	8.7639	1,841
79	97,371	5.3425	5,202
80	3,080,912	7.5563	232,803
84	3,280,296	7.6378	250,542
85	192,890	7.8629	15,167
86	43,404	7.8772	3,419
87	35,942	7.8932	2,837
88	43,534	8.0792	3,517
89	36,889	7.8520	2,896
90	97,059	7.4782	7,258
91	152,791	7.5776	11,578
92	63,985	7.8873	5,047
93	100,859	7.6542	7,720
94	18,207	7.8596	1,431
95	74,125	8.2844	6,141
96	36,287	7.8547	2,850
97	107,547	5.2175	5,611
98	31,495	3.2806	1,033
99	28,554	4.5321	1,294
100	154,174	5.7436	8,855
101	87,525	4.6950	4,109
102	462,899	4.2833	19,827
103	4,344,778	3.1595	137,273
104	121,897	7.7855	9,490
105	544,971	10.2181	55,686
106	39,169	5.3576	2,099

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Rate Schedule Number	1954 Volume Mcf @ 14.65	1958 Unit Revenue* ¢/Mcf @ 14.65	Indicated Revenue, Dollars
107	805	4.3478	35
108	32,926	4.5946	1,513
109	3,387	4.4697	151
110	138,764	8.3166	11,540
111	84,945	4.6562	3,955
112	4,151	6.0312	250
113	32,288	5.3973	1,743
114	403	5.3218	21
115	26,222	10.9982	2,884
	32548		
116	204,603	10.2976	21,069
117	538,121	5.7224	30,793
118	1,650	9.2767	153
119	5,301	5.1100	271
120	101,483	4.7990	4,870
121	22,823	5.2381	1,195
122	36,410	7.5135	2,736
123	232,046	11.5244	26,742
124	619,703	10.3458	64,113
125	191,436	6.0762	11,632
126	406,922	6.0078	24,447
127	34,931	7.2141	2,520
128	9,317	10.1207	943
129	123,711	7.1212	8,810
130	37,083	10.8685	4,030
131	11,352	6.4572	733
132	75,577	10.6087	8,018
133	103,340	12.5289	12,947
134	61,447	8.6323	5,304
135	41,711	8.8020	3,671
136	36,867	13.1490	4,848
137	46,195	12.7013	5,867
138	66,068	7.2853	4,813
139	14,806	12.0996	1,791
141	36,985	6.1639	2,280
142	71,013	7.6115	5,405
146	607,118	8.7601	53,184
147	36,003	3.2873	1,184
153	1,382	12.6214	174
154	74,026	6.2096	4,597
155	39,305	21.7206	8,537
156	8,734	2.6591	232

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Rate Schedule Number	1954 Volume Mcf @ 14.65	1958 Unit Revenue* ¢/Mcf @ 14.65	Indicated Revenue, Dollars
160	7,382	5.9049	436
161	39,197	4.2690	1,673
162	424	3.5165	15
163	68,901	6.1150	4,213
164	5,588	5.9571	333
165	396,260	5.9972	23,765
166	1,174	6.1844	73
168	16,316	4.4223	722
170	16,921	7.8596	1,330
171	14,614	7.8596	1,149
172	27,760	7.8596	2,182
173	9,320	5.6734	529
174	765	5.0633	39
179	175,813	5.5000	9,670
		32549	
180	46,926	5.2979	2,486
182	57,572	15.0952	8,691
184	37,216	2.8611	1,065
185	30,849	3.0569	943
190	1,695	6.3380	107
191	13,969	4.6320	647
199	203,440	5.5765	11,345
203	18,271	7.9592	1,454
204	10,057	7.0014	704
205	128,330	6.2356	8,002
210	110,687	4.8490	5,367
223	7,552	7.3794	557
224	219,616	9.0741	19,928
225	190,420	12.3310	23,481
226	22,878	5.3206	1,217
238	13,796	6.3051	870
244	145,691	14.0200	20,426
245	416,003	25.9279	107,861
250	98,997	5.3115	5,258
P.C.C. #1	33,584	5.9900	2,012
P.C.C. #2	218	5.9900	13
TOTAL	20,716,526		$1,463,009

*Unit revenue for each contract was obtained by dividing total revenue by wellhead volume. Data for 1958, the latest available, was used unless deliveries ceased in some prior year, in which case the unit revenue for that last year of deliveries was used.

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SCHEDULE V

PHILLIPS PETROLEUM COMPANY AND SUBSIDIARIES
DOCKET NO. G-1148
EFFECT OF VARIOUS ADJUSTMENTS AS BETWEEN
PHILLIPS' AND THE EXAMINER'S COST OF SERVICE

Line No.		I	II	III	IV	V	VI	VII	VIII	IX	Line No.
		Phillips								Examiner	
1.	Rate of Return	12%	12%	12%	12%	12%	9.25%	9.25%	9.25%	9.25%	1.
2.	Total Provision for Fed. Income Taxes Includes	Tax Benefits	Tax Benefits	Tax Benefits	Tax Benefits	Tax Benefits	Tax Benefits	Tax Benefits	Tax Benefits	No Tax Benefits	2.
3.	Exploration Allocated to Gas	59.5404%	59.5404%	45.2242%*	43.25%***	41.25%**	45.2242%*	43.25%***	41.25%**	30.4596%	3.
4.	Components of Rate Base										4.
5.	Natural Gas Leases	$31,174,819	$ 31,174,819	$ 31,174,819	$ 31,174,819	$ 31,174,819	$ 31,174,819	$ 31,174,819	$ 31,174,819	$ 31,157,055	5.
6.	Joint Product Leases—Gas	23,942,940	23,942,940	23,942,940	23,942,940	23,942,940	23,942,940	23,942,940	23,942,940	23,929,281	6.
7.	Gathering Systems	29,635,783	29,635,783	29,635,783	29,635,783	29,635,783	29,635,783	29,635,783	29,635,783	29,612,385	7.
8.	Residue Systems	2,763,353	2,763,353	2,763,353	2,763,353	2,763,353	2,763,353	2,763,353	2,763,353	2,763,352	8.
9.	Subtotal	87,516,895	87,516,895	87,516,895	87,516,895	87,516,895	87,516,895	87,516,895	87,516,895	87,462,073	9.
10.	Exploration	34,114,490	34,114,490	25,857,028	24,728,275	23,584,771	25,857,028	24,728,275	23,584,771	17,405,416	10.
11.	Subtotal	121,631,385	121,631,385	113,373,923	112,245,170	111,101,666	113,373,923	112,245,170	111,101,666	104,867,489	11.
12.	Working Capital—Less ⅓ Actual Fed. Income Taxes	—0—	5,475,176	5,581,750	5,596,042	5,610,525	6,531,639	6,537,731	6,543,904	8,028,654	12.
13.	Total Rate Base	$121,631,385	$127,106,561	$118,955,673	$117,841,212	$116,712,191	$119,905,562	$118,782,901	$117,645,570	$112,896,143	13.
14.											14.
14.	Cost of Service										14.
15.	Direct Lease Expense	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,657,810	$ 4,655,156	15.
16.	Indirect Lease Expense	5,355,255	5,355,255	5,355,255	5,355,255	5,355,255	5,355,255	5,355,255	5,355,255	5,651,952	16.
17.	Gathering & Residue Systems Expense	8,580,546	8,580,546	8,580,546	8,580,546	8,580,546	8,580,546	8,580,546	8,580,546	8,574,468	17.
18.	Gas Purchases	18,262,419	18,262,419	18,262,419	18,262,419	18,262,419	18,262,419	18,262,419	18,262,419	18,248,001	18.
19.	Regulatory Expense	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	19.
20.	Subtotal	37,256,030	37,256,030	37,256,030	37,256,030	37,256,030	37,256,030	37,256,030	37,256,030	37,529,577	20.
21.	Exploration Expense	15,016,511	15,016,511	11,419,274	10,920,782	10,415,774	11,419,274	10,920,782	10,415,774	7,282,657	21.
22.	Total	52,272,541	52,272,541	48,675,304	48,176,812	47,671,804	48,675,304	48,176,812	47,671,804	44,812,234	22.
23.											23.
23.	Increased Gas Purchases & Production Taxes:										23.
24.	Gas Royalties	3,096,196	3,195,425	2,753,654	2,701,188	2,665,368	2,296,484	2,269,020	2,153,700	1,159,273	24.
25.	Gross Production Taxes	1,072,681	1,107,059	954,006	935,830	923,420	795,620	786,104	746,152	250,659	25.
26.	Casinghead Gas	4,464,876	4,607,968	3,970,911	3,895,253	3,843,598	3,311,649	3,272,044	3,105,748	—0—	26.
27.	Dry Gas	1,612,310	—0—	—0—	—0—	—0—	—0—	—0—	—0—	—0—	27.
28.	Total	10,246,063	8,910,452	7,678,571	7,532,271	7,432,386	6,403,753	6,327,168	6,005,600	1,409,932	28.
29.											29.
29.	Return Provision for Taxes:										29.
30.	Return on Rate Base	14,595,766	15,252,787	14,274,681	14,140,945	14,005,463	11,091,265	10,987,418	10,882,215	10,442,892	30.
31.	Actual Liability for Federal Income Taxes	7,729,591	8,290,795	7,971,082	7,928,199	7,884,752	5,121,412	5,103,136	5,084,619	615,160	31.
32.	Tax Benefits	7,465,477	7,616,045	6,918,029	6,821,761	6,724,236	6,318,999	6,230,501	6,140,848	—0—	32.
33.	Total	29,790,834	31,159,627	29,163,792	28,890,905	28,614,451	22,531,676	22,321,055	22,107,682	11,058,052	33.
34.	Total Cost of Service	$ 92,309,438	$ 92,342,620	$ 85,517,667	$ 84,599,988	$ 83,718,641	$ 77,610,733	$ 76,825,035	$ 75,785,086	$ 57,280,218	34.
35.	Return & Tax Benefits as a Percentage of Rate Base	18.14%	17.99%	17.82%	17.79%	17.76%	14.52%	14.50%	14.47%	9.25%	35.

NOTES TO SCHEDULE V:
Column I shows the cost of service as presented by Phillips. Column IX shows the results obtained by the Examiner. Columns II through VIII, inclusive, show seven calculations based upon variations from Phillips' cost of service.
The increased cost of dry gas is excluded (line 27) from each of the seven calculations II through VIII. In each of these seven calculations, an amount is included (line 12) for working capital less ⅓ of actual Federal income tax liability. The amounts included at line 12 vary from one column to the next in direct proportion to the change in Federal income taxes, line 31.
The amounts for Increased Gas Purchases & Production Taxes (lines 24, 25 and 26) vary directly with the total cost of service.
At line 1 for each column is shown the rate of return on which that calculation is based. At line 3 for each column is shown the percentage of exploration costs allocated to gas. As indicated by the asterisks, the derivation of the exploration percentages for Columns III through VIII, inclusive, is explained on the attached sheets.

*The 45.2242% is the result of a computation made, but not sponsored, by Caplan during cross-examination (123:16486). Reference is also made to this computation and the 45.2242% in Phillips' Exceptions to the Examiner's Decision at page 107.

**The 41.25% is the result of correcting a basic error in the RAR method. The computations are described in Phillips' Exceptions to the Examiner's Decision, pages 114, 115, 116.

***The figure 43.25% represents the ratio of the net investment in gas producing leaseholds and corresponding intangible development costs to the total net investment in all producing leaseholds and their corresponding intangible development costs. The various exploration accounts to be allocated between oil and gas consist of leasehold costs and well drilling costs, rather than production equipment costs. Pages 15 and 16 of Exhibit 282 provide a listing of the exploration accounts which include lease rentals, expired and surrendered leases, dry holes, lease development AFE's, and drilling equipment. The ratio is developed from the record made in Docket No. G-1148, as follows:

A. Compile the total net investment (including an allocated part of general assets) in producing leaseholds and intangible development costs.

Dry Gas Leases	84.16%[1]	of $ 50,201,147[2]	or $ 42,249,285
100 % Oil Leases	58.28%[3]	of $ 46,109,957[4]	or $ 26,872,883
Joint Product Leases	58.28%[3]	of $163,420,819[4]	or $ 95,241,653
Royalties and Overriding Royalties			$ 1,230,948[5]
			$165,594,769

B. Segregate the part applicable to gas producing leases.

Dry Gas Leases	100 %	of $ 42,249,285	or $ 42,249,285
Joint Product Gas	30.838%[6]	of $ 95,241,653	or $ 29,370,621
			$ 71,619,906

C. It follows that the ratio of net investment in gas producing leaseholds and intangible development costs to total net investment in producing leaseholds and intangible development costs is $71,619,906 divided by $165,594,769, or 43.25%.

[1] Leaseholds and intangible development costs constitute 84.16% of the net investment in dry gas producing leases.

(Footnotes Continued on Next Page)

Exhibit 354, sheet 6, year 1954, Natural Gas Department.

Leaseholds	$ 9,821,399	
Intangible Development Costs	29,686,930	
	39,508,329	84.16%
Lease Equipment	7,437,618	15.84%
	$46,945,947	100.00%

[2] The total net investment in dry gas producing leases, including an allocated part of general assets, is $50,201,147 and is shown at line 11, page 17, of Exhibit 282.

[3] Leaseholds and intangible development costs constitute 58.28% of the total net investment in producing leases of the Oil and Gas Production Department.

Exhibit 354, page 6, year 1954, Oil and Gas Production Department.

Leaseholds	$ 16,859,364	
Intangible Development Costs	97,430,872	
	114,290,236	58.28%
Lease Equipment	81,821,998	41.72%
	$196,112,234	100.00%

[4] The total net investment, including an allocated part of general assets, of the Oil and Gas Production Department is shown at line 8, page 18, Exhibit 282: 100% Oil Leases $46,109,957 and Joint Product Leases, $163,420,819.

[5] The net investment in royalties and overriding royalties is $1,230,948 which comprises the four royalty items shown on page 14 of Exhibit 282.

[6] Computed in accordance with the relative cost procedure illustrated on page 11 of Exhibit 282, the percentage of Joint Product net investment in leaseholds and intangible development costs attributable to gas is 30.838%.

Computation:

$$\frac{\frac{\$\ 42,249,285}{226,681,178}\ (149,009,734)}{\frac{\$\ 42,249,285}{226,681,178}\ (149,009,734) + \frac{\$26,872,883}{13,056,309}\ (30,261,670)} = 30.838\%$$

32571

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
PHILADELPHIA, PENNSYLVANIA

May 6, 1960

Federal Power Commission
Washington 25, D. C.

Re: *Phillips Petroleum Company—Docket Nos. G-1148, et al.*

Gentlemen:

This will respond to the Offer of Settlement submitted by Phillips Petroleum Company herein by letter of April 6, 1960. For reasons outlined below, the Eastern Seaboard Companies* do not find the terms of the Offer acceptable in its present form and are compelled to oppose it.

We agree with the statement set forth in the concluding sentence of the first paragraph of Phillips' letter, to the effect that "the entire natural gas industry has been operating for a long time in a state of indecision and confusion". Obviously, everyone, including the Commission, would agree that this is an undesirable situation which should be remedied with the least practicable delay. We do not agree, however, that the solution suggested by Phillips is designed to achieve the intended purpose. On the contrary, the proposal, if adopted, would do nothing but perpetuate the "state of indecision and confusion" and would negate five years of effort on the part of the Commission's Staff, Phillips and many intervenors to build a record on

* Long Island Lighting Company, Philadelphia Electric Company, Public Service Electric & Gas Company, The United Gas Improvement Company.

the basis of which meaningful regulatory principles may be established.

This Commission has said on numerous occasions that it does not believe it should use its conditioning authority under Section 7 of the Act to fix producer prices; that rates are intended to be established under the rate making sections, 4 and 5.

This is a proceeding under those sections and the record is complete, at least as to all issues involving the determination of cost of service and necessary revenue level. Complicated though the facts may be, the Examiner understood them and rendered his decision upon them; the Commission can and should do likewise, and without delay, in order that ground rules under which proceedings of this type are to be conducted may be established for and understood by the entire industry.

Phillips suggests that its cost of service amounts to $92 million but that it is willing to settle this case on the basis of its own negotiations with its purchasers for $70 million. While we are in no position without further information to evaluate the merits of this proposal in terms of net revenues to the Company,* we can say that the basis upon which it is founded is entirely unacceptable to us. While we would be willing to negotiate with Phillips at any time, with a view toward arriving at a fair and just settlement of the controversy here involved, such negotiations would have to be within the framework of the Act as it has been interpreted by the Courts. Since we do not view Phillips' proposal of April 5 as meeting that standard, however, we are unequivocally opposed to it.

* The 1960 level of which preliminary examination indicates to be far in excess of the level found by the Examiner to be reasonable.

Copies hereof have been served this date upon all parties of record.

Very truly yours,

J. DAVID MANN, JR.
J. David Mann, Jr.
Attorney for the
EASTERN SEABOARD COMPANIES

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32643

[Mimeo., p. 1]

Before Commissioners: Jerome K. Kuykendall, Chairman; Frederick Stueck and Arthur Kline

Docket No. G-1148

Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10359, G-10793, G-10883, G-11125, and G-11217

Opinion No. 338

Opinion and Order Determining Cost of Service and Terminating Proceedings

(Issued September 28, 1960)

This is a rate proceeding under Sections 4 and 5 of the Natural Gas Act and is a sequel to the decision of the United States Supreme Court on June 7, 1954 in *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672 which reversed the determination made by this Commission and held that we had jurisdiction over the wholesale rates in interstate commerce of the Phillips Petroleum Company even though it is an independent producer of gas and not a pipeline company. In this proceeding rates have been determined

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for Phillips by the presiding examiner in his decision issued April 6, 1959, and the issues involved are now before us after the filing of exceptions to his decision and oral argument before the Commission.

The original proceeding arose on October 28, 1948, 7 FPC 983, when we instituted an investigation under Section 5(a) of the Natural Gas Act to determine whether Phillips was a natural-gas company within the jurisdiction of the Commission and whether its rates were unjust or unreasonable. After a hearing, the Commission determined on August 16, 1951, (10 FPC 246) that Phillips was not a natural gas company, but this decision was reversed by the Court of Appeals for the District of Columbia,[1] which, in turn, was affirmed by the Supreme Court of the United States in the above mentioned decision.

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[Mimeo., p. 2]

As a result of the Court decisions, we vacated on November 22, 1954, our previous termination of the proceedings in G-1148 and reinstituted our Section 5(a) investigation of Phillips' rates. By later orders we consolidated the proceedings in Docket No. G-1148 with proceedings under Section 4(e) of the Gas Act arising out of the suspension of increased rates filed by Phillips in the other dockets listed in the title above. The increased rates proposed in these dockets became effective at various dates subject to refund.

The hearings in the consolidated proceedings commenced on June 26, 1956 and, after 82 hearing days, were closed on December 18, 1957. The parties include Phillips, the staff of the Commission and some thirty-one interveners. At the October 15, 1957 session of the hearing after the presentation of the cases of Phillips and the staff, cross-examination

[1] *State of Wisconsin* v. *F.P.C.*, 205 F. 2d 706 (CADC 1953).

thereon and the supplying by Phillips of additional data at the request of various interveners, counsel for the Wisconsin Public Service Commission moved that the examiner direct the staff to make further studies and present additional data in the record to fill alleged gaps. The examiner and subsequently the Commission denied Wisconsin's request.

On December 2, 1957, two weeks before the close of the hearing, staff counsel moved the examiner to grant a recess of six months to permit the staff to make a further investigation for the purpose of adding to the record data with respect to the cost of Phillips' joint product wells, broken down on an area basis, so as to assist the Commission in fixing rates on an area basis rather than a company-wide basis if it should desire to do so. The examiner denied this motion on the ground that the problems raised had been obvious for some time, that the additional evidence would not necessarily be sufficient, and that granting the motion would result in great delay in the completion of the proceedings. The Commission affirmed the examiner's ruling on this matter also.

Briefs were filed by Phillips, a number of interveners and the staff; and the examiner issued a decision on April 6, 1959 in which he thoroughly analyzed the questions at issue. Thereafter exceptions were filed by Phillips, Minneapolis Gas Company, San Diego Gas & Electric Company, Panhandle Eastern Pipe Line Company, Northern Natural Gas Company and Permian Basin Pipeline Company, Pacific Gas and Electric Company (P.G.&E.), Southern California Gas Company and Southern Counties Gas Company of California (Southern California Companies), Minneapolis Gas Company, Michigan-Wisconsin Pipe Line Company, El Paso Natural Gas Company, the Michigan Public Service Commission, the State of Wisconsin and the Public Service Commission of Wisconsin (Wisconsin), the Public

Utilities Commission of the State of California and the staff of this Commission. The Eastern Seaboard Companies[2] filed a statement to the effect that they didn't specifically except to any portion of the examiner's

decision but asked to participate fully in the oral argument. The Mid-Continent Oil & Gas Association moved to file a brief *amicus curiae* and a brief in which it objected to the use of the cost of service method of fixing rates for independent gas producers and urged that the present case, in which the evidence was based on cost of service, be decided in such a manner that it not be a precedent in other independent producer rate cases as to the standard for regulation or even as to the cost of service method itself, if that method should be used.

Oral argument was held before us on October 1 and 2, 1959. Representatives of Phillips, the Eastern Seaboard Companies, the California Commission, the Wisconsin Commission, several other intervenors[3] and our staff participated. The issues in this proceeding are thus before us and many questions arise. The most important question is whether the cost of service method should be applied in this proceeding. Assuming that it is necessary for us to use the cost of service method here, very important questions relate to the allocation of costs, particularly exploration costs between oil and gas, the effect of rate increases on the cost of purchased gas, the acreage to be included in the rate base, rate of return and the effect to be given to our cost of service determination on Phillips' rates.

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2 Long Island Lighting Company, Public Service Electric and Gas Company, Philadelphia Electric Company and the United Gas Improvement Company.

3 City of Detroit, Michigan-Wisconsin, P.G.&E., the Southern California Companies, Minneapolis Gas Company and San Diego Gas & Electric Company.

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[Mimeo., p. 4]

THE PHILLIPS PETROLEUM COMPANY

Phillips sells more natural gas in the United States than any other oil and gas producer; and it is the largest producer of liquids condensed from natural gas. It also engages in various phases of the oil and petro-chemical business with operations spread throughout the United States and in several foreign countries. Its operations include the exploration for and the production of oil and gas, the purchase of oil and gas from other producers, the gathering of natural gas, the processing of natural gas in gasoline plants for the extraction of liquid hydrocarbons, the refining of crude oil and other petroleum products, the manufacture and sale of various chemicals, the operation of oil pipelines, the sale of petroleum products, and research and development.

While Phillips is the largest seller of natural gas, its annual revenues from this source were but 6 percent of its total gross income in 1955. In the test year 1954, it sold 688,811,312 Mcf, of which 491,178,953 or 71.3 percent were sales for resale in interstate commerce. As the examiner notes, Phillips' natural gas operations extend from the Gulf Coast to Montana and Wyoming with the greatest concentration of sales occuring in Texas, Louisiana and Oklahoma.

Three of Phillips' departments are directly concerned with natural gas. These are the Natural Gas Department, which operates all wells producing dry gas only and all gas gathering systems, the Natural Gasoline Department, which operates the gasoline plants, and the Oil and Gas Production Department, which operates wells producing both oil and gas, including gas condensate wells. In addition, several service departments perform services in connection with natural gas operations. As a result of the operations of these departments, Phillips sells dry natural

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gas, gas-condensate well gas, raw casinghead gas in the field and from gathering systems, and residue gas at the outlet of its gasoline plants after the saleable liquids have been extracted. In the year 1954, a total of 375,690,912 Mcf was produced, 226,681,178 Mcf in the Natural Gas Department and 149,009,734 Mcf in the Production Department, and an additional 407,984,210 Mcf were purchased.[4]

32647[5]

[Mimeo., p. 5]

REGULATION OF NATURAL GAS PRODUCERS' PRICES

With the full proceedings before us involving the largest independent producer of natural gas from the standpoint of sales in interstate commerce the time has arrived when the Commission can express its views on the policies which must be followed in order to regulate the rates of independent producers of natural gas in a sane, sensible and effective manner. Heretofore, we have been confined to the record of particular cases, which generally did not afford a basis for employing the experience which we have acquired in the many cases which have come before us, including, now, this one.

Experience of the Commission in this case, as well as in many other producer rate cases during the last five years, has shown, beyond any doubt, that the traditional original cost, prudent investment rate base method of regulating utilities is not a sensible, or even a workable method of fixing the rates of independent producers of natural gas. The fact that, in this case, we can, by making numerous arbitrary allocations and estimates, arrive at a calculated unit cost of gas does not prove to anyone's satisfaction, including ours, that we have thus solved the problem of

[4] These volumes relate to the United States only. The difference between the amounts produced and purchased and the amounts sold consists of company uses, losses and return to leases, etc.

fixing prices for natural gas sold by independent producers. We recognize that the use of this method for regulating utilities provides only some possible aid toward solving, but not the answer to, the problem of fixing producers' rates.

Producers of natural gas cannot, by any stretch of the imagination, be properly classified as traditional public utilities. Justice Harlan, dissenting in the recent case of *Sunray Oil Co.* v. *F.P.C.*, 364 U.S. 137 at p. 160, characterized the difference as follows:

> ". . . A pipeline performs a service akin to those traditionally performed by public utilities. The independent producer, on the other hand, is unique among the objects of public-utility regulation because it is not engaged in rendering a service to the public in the conventional sense of that concept, but rather simply in selling a commodity which it owns. . . ."

A natural gas pipeline, under our regulation, usually has a fair opportunity to earn a fair rate of return, but such is not necessarily the case with a producer. The pipeline investor is reasonably assured of the financial feasibility of a project before any funds are expended for construction. The pipeline constructs facilities only after the issuance of a certificate of public convenience and necessity and reasonable assurance of fair rates. The producer must invest his funds prior to ascertaining whether he will have anything to sell or whether, if he does, he will have an adequate market. Thus it is clear that in regulating producers, we are faced with problems entirely different from those presented by an ordinary public utility. Furthermore, to fix rates of gas producers simply by allowing a return on investment or rate base will penalize the efficient or fortunate producer and will unduly reward the inefficient or unfortunate producer. As Justice Jackson put it in his

dissent in *F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591 at 649.

[Mimeo., p. 6]

> ". . . The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the result than in a game of poker."

Virtually the only situation in which the investment would have a real relationship to the return is where the producer has purchased fully developed acreage at a current fair price. Otherwise the determination of the cost of a producers' assets upon the happening of a certain event, or at a certain point in time will produce unrealistic and inequitable results. Under the cost rate base method the producer who first takes the risk in an area and proves it productive will get the least return, for he will undoubtedly pay less for his rights than those who come in later after the area is proved.

While the examiner felt that the traditional rate base method of rate regulation could ultimately be successfully used to regulate producers' rates, we are convinced that such a method is unworkable, and will produce fallacious results. This conclusion is based not only upon our examination of the record in this case but to an even greater extent upon the knowledge and expertise we have gained from the many producer cases which we have had before us, either after an examiner's decision or upon some matter of procedure or evidence in pending cases, and from years of study of these problems.

We are not dealing with a service requiring certain equipment at known costs. We are dealing in many instances with one of two commodities produced with the same equipment and processed to varying degrees prior

to sale. The price of the second commodity, oil, is unregulated, as is that part of the gas, which is sold in intrastate commerce or other transactions not subject to our jurisdiction, as well as the products which are extracted prior to shipment. Thus we are faced with the extremely difficult problem of allocating costs between the regulated and unregulated products. The record shows that none of the experienced, diligent, and intelligent experts who have labored on this problem have proposed any allocations which were acceptable to other experts. Every method of allocation advanced was shown to have at least some element of guesswork or to ignore some facts.

While we must make allocations in all rate cases, the amounts involved in electric and gas pipeline cases have been comparatively small and the allocations relatively simple. In the case of the producer, the amounts involved in the allocations of costs are major in size and extremely difficult to make. The result is that a producer actually could become bankrupt, or could make enormous profits, depending merely on the methods of allocation used. We do not say that allocations cannot be made. We say that in this kind of case the rates should not be wholly dependent upon them.

Further experience may enable us to refine and improve our allocation methods, but it is clear that the calculation of the unit cost of gas is, and will be an inexact, complex, unsatisfactory, and time consuming process, fraught with controversy. The result finally reached may give the illusion

of accuracy since mathematical processes are involved, and a definite price per Mcf is the final result. But such a result must be tested against the realities of the market place. Thus, prices calculated solely on the cost rate base principle cannot be accepted if they are higher than a buyer will pay, or lower than a seller will accept.

When an unrealistic result is reached, the formulae for allocations must be changed, in order to bring about a reasonable result. The allocation methods then become a means of supporting a result already arrived at, rather than a means of arriving at a result which was previously unknown.

Another difficulty in determining cost of gas per unit is presented by the necessity of using estimates of reserves of gas, which can never be precise and have been shown to be highly inaccurate in many cases, with qualified experts differing as much as 100 percent over reserves in the same formations. See e.g., *El Paso Natural Gas Company*, Docket No. G-12580, 22 FPC 900, page 904 and 918, *et seq.*

The rate base cost of service method entails consideration of the tax laws applicable to percentage depletion and intangible well-drilling costs. (I.D.C.) Thus these difficult and disputatious matters, the effects of which are extremely difficult to predict, become major issues, along with the methods of allocation. Instead of simplifying, they obfuscate and hinder the solution to the problem of arriving at a just and reasonable rate for natural gas sold by a producer.

Ridiculous results will be reached among the great number of producers and owners of interests if costs should be the only basis for regulation. In unitized fields many single wells have as many as fifty part owners. If cost is to be the sole criterion, each owner would be required to show his costs. Any other course would presumptively be unlawful and confiscatory as to those owners whose costs were not shown. Under the rate base method, Phillips' new rates could not be said to be fair for co-owners. Thus from each well in the United States every Mcf of gas might have a different price tag. Gas from one well might well range in cost from 1 cent to 10 dollars per Mcf.[5]

[5] See *Pan American Petroleum Corp., et al.*, Opinion 310, 19 FPC 463.

In this connection it is to be noted that much of the gas which Phillips sells into interstate commerce is purchased from thousands of independent producers whose rates under percentage-type casinghead contracts are dependent upon Phillips' rates. We discuss this problem more completely below under the subject of Expenses. It should be pointed out at this point, however, that the percentage-type of casinghead contracts which share the proceeds of sale, give automatic rate increases for thousands of producers selling to Phillips with no possible determination by us of actual just and reasonable prices to each seller for such casinghead sales.

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[Mimeo., p. 8]

We must also consider the interests of the many royalty owners who are paid a percentage of the price received for the products. If cost is to completely control price, landowners would be well advised to lease only to the producing companies who have and can show high costs. Thus low cost producers who must replace diminishing resources would find it increasingly difficult to obtain new leases. In keeping with such a showing of higher costs we must bear in mind the fact that almost half of the markets for gas in this country are not under our jurisdiction. This gives many producers substantial room in which to manipulate their sales in order to sell only in interstate commerce the gas with the highest production costs.

In his concurring opinion in *Colorado Interstate Gas Co.* v. *F.P.C.*, 324 U.S. 581, Justice Jackson anticipated the chaos of such a situation when he stated at page 610:

> "To let rate-base figures, compiled on any of the conventional theories of rate-making, govern a rate for natural gas seems to me little better than to draw figures out of a hat. These cases confirm and strengthen me in the view I stated in the *Hope* case that the entire

rate-base method should be rejected in pricing natural gas, though it might be used to determine transportation costs. These cases vividly demonstrate the delirious results produced by the rate-base method. These orders in some instances result in three different prices for gas from the same well. The regulated company is a part owner, an unregulated company is a part owner, and the land owner has a royalty share of the production from certain wells. The regulated company buys all of the gas for its interstate business. It is allowed to pay as operating expenses an unregulated contract price for its co-owner's share and a different unregulated contract price for the royalty owner's share, but for its own share it is allowed substantially less than either. Any method of rate-making by which an identical product from a single well, going to the same consumers, has three prices depending on who owns it does not make sense to me. . . ."

Another problem inherent in regulation of producers on a cost basis is the administrative burden of having a full cost rate case for each of the thousands of independent producers. And one case per producer would not be sufficient. The uncertainty of the business assures that a great many producers will have substantial cost and revenue fluctuations from year to year and, if cost were our only criteria, the interests of both consumers and producers would require a full cost hearing repeatedly for each producer. Thus adherence to the original cost rate base method of regulation results in the necessity of a full scale, company-wide cost study of a producer in order to determine whether the price contained in any one contract represents revenue to which the company is entitled. If the Commission suspends a two mill escalation in a contract, and then processes that case in the usual manner, the same work

must be done as would be done in a Section 5(a) investigation. This is one of the main reasons why this long drawn out case must

necessarily result in the disposition of relatively few of Phillips' many filings. Certainly we cannot judge Phillips' precise revenue requirements for 1960 and the future based on its costs for 1954.

An illustration of the administrative impossibility of separate determinations for all producers' rates is found in the fact that there are 3,372 independent producers with rates on file with this Commission.[6] The producers have on file with us 11,091 rate schedules and 33,231 supplements to these schedules. Currently, 570 of these producers are involved in 3,278 producer rate increase filings now under suspension and awaiting hearings and decisions. The number of completions of independent producer rate cases per man-year during the first 6 years following the Phillips decision indicate that nearly 13 years would be required for our present staff to dispose of the 2,313 cases pending on July 1, 1960. Within this 13-year period an additional estimated 6,500 cases would have been received.

Thus, if our present staff were immediately tripled, and if all new employees would be as competent as those we now have, we would not reach a current status in our independent producer rate work until 2043 A.D.—eighty-two and one half years from now. Of course, we could expect to improve our techniques and thus shorten the time required to process these cases. If we increased our efficiency one thousand percent, we would achieve current status in 1968—eight and two-tenths years from now. And regardless of how much our staff is increased every case must still

[6] To these add 15,435 non-filing co-owners whose rights should also be considered under any rate base theory.

be reviewed by us and our own time and capacity is not unlimited.[7]

As the cost evidence in this case indicates, and as the examiner found in this case even absent sales manipulations, our function in regard to producers may well become one of permitting increases in gas prices if each producer is to be regulated solely on a cost basis. In this connection, it may be noted that at this time 11 producer rate increase cases have had full hearings and have been finally decided by us on a cost basis. In 10 of these

cases the costs showed that the proposed prices were more than justified.[8] In the other case, *H. L. Hunt*, 19 FPC 748, difficulties with an affiliated seller's rate prevented us from deciding the rates of the applicant. Three 5(a) proceedings against producers have been fully concluded and in all three the producers' prices were shown to be justified on a cost basis.[9] Phillips will add one more to this list.

Of 30 producer rate increases submitted with cost data up to this time, 16 have been accepted by our staff when a study of the data showed that the prices were more than justified even though every accounting issue was resolved against the

[7] The Bills introduced into Congress to eliminate some smaller producers from our jurisdiction would not actually reduce these figures to any substantial extent. Field unitizations, production fluctuations from year to year, fluctuations in the allowables set by the states, processing contracts and various other factors would prevent such a law from reducing our workload to any great extent beyond that which it has already been reduced by our own regulations in regard to filings.

[8] *Wunderlich Development Co.*, 15 FPC 690, *Davidor & Davidor*, 15 FPC 1236, *Christie Mitchell*, 15 FPC 751, *William Negley*, 17 FPC 550, *Bayview Oil Co.*, 21 FPC 405, *Rebstock & Reeves*, FPC , *Sinclair Oil Co.*, 22 FPC 53, *Harper Oil Co.*, 17 FPC 803; *Hassie Hunt Trust*, 21 FPC 37, *Monsanto Chemical Co.*, 22 FPC 1077.

[9] *Gillring Oil Co.*, 20 FPC 770, *Ralph E. Fair*, 20 FPC 810, *C. V. Lyman*, 22 FPC 557.

applicant. The remaining 14 increases have either been settled or are awaiting hearings because of incomplete or unacceptable cost data but not because the rates involved appeared to be wholly out of line with the costs. The indications from these and filings now being studied make it quite clear that regulation of producers on a company-by-company rate base method will in all probability result in higher consumer prices than we would otherwise have.[10] Since the cost rate base method seems almost always to produce the higher rates it appears that consumers, in most instances, will be thoroughly protected if we place more reliance on existing prices and on applicable economic principles.

In fact, rigid adherence to the rate base method will, in many cases, price the producers' gas completely out of the market. This fact is now abundantly clear: Regardless of variations in allocation methods, allowance for incentives, and other disputed factors, computations of the cost of natural gas which have been presented in the many cases before us, show that natural gas has been, in almost all instances, substantially underpriced.

Furthermore, it is clear that contracts for the sale and purchase of natural gas which were in force prior to June 7, 1954, while presumed as a matter of law to be reasonable, *Wichita Railroad & Light Co.* v. *Public Utilities Commission of Kansas*, 260 U.S. 48, are, in most cases, actually reasonable, as tested by cost rate-making principles. Thus, these old contracts provide starting points, which with relatively few exceptions are fair, or more than fair to consumers.

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[Mimeo., p. 11]

From the foregoing, it follows that effective regulation of the price of natural gas must be on some more manageable

[10] The main exception to the higher cost situation exists in the gas produced from the Panhandle-Hugoton Field in Texas, Oklahoma and Kansas, which was developed near the turn of the century and has relatively more shallow producing horizons holding tremendous reserves.

plan than the rate base method. Thus it is clear that the better method would be to establish fair prices for the gas itself and not for each individual producer. While the evidence here is sufficient to allow a determination on a mathematical basis of the revenue Phillips requires, it appears that the ultimate solution to producer regulation will be in the determination of fair prices for gas, based on reasonable financial requirements of the industry and not on the particular rate base and expenses of each natural gas company.

We are, simultaneously with the issuance of this opinion and order, promulgating a policy statement setting forth rate guidance levels for various producing areas of the country. We are thereby establishing two prices for each of these areas; (1) a price applicable to new contracts above which we will not certificate new sales without justification of the price; (2) a price pertaining to existing contracts, above which we shall suspend price escalations.

This schedule of prices is only for guidance and does not constitute any determination of just and reasonable rates and will not foreclose any person from justifying a particular rate in any area. Prices now shown on this schedule will no doubt be revised from time to time, as experience indicates they should be. Other revisions and refinements no doubt will also be made, such as changes in the boundaries of the areas, provisions for variations in physical qualities of the gas, terms of delivery, and other factors.

Our ulfimate objective will be to set prices in all producing areas which will be adequate to maintain the gas supplies needed by the consumers of the nation, but at prices that are no higher than are necessary to accomplish that purpose.

We intend to make use of cost data we have obtained in the past and we intend to acquire and consider cost information in the future. We also intend to use all information of an economic nature we have acquired, and to continue to

acquire and use such data in the future. Costs incurred in the past are only a part of the body of information pertaining to the economics of the gas producing industry which is necessary for intelligent regulation of that industry.

Costs pertaining to the representative sampling of the industry in any one area must be accepted as part of the basis for fixing rates for all producers in the area. Obviously, as we have shown previously, it is impossible as well as absurd to obtain the cost data for each and every one of the thousands of producers under our jurisdiction.

We fully realize that some persons will contend that the plan of rate regulation we here announce is not lawful and that we are bound by *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC, 1956), *certiorari* denied 352 U.S. 829, to calculate a rate base and determine a rate of return, at least as a point of departure. If this contention is correct, then, as a practical matter, adequate regulation of producers appears to be impossible under existing law.

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[Mimeo., p. 12]

Nowhere in the Natural Gas Act is there as much as one word which indicates that this Commission must use a rate base in determining just and reasonable rates. The correct construction of the Natural Gas Act on this question, both as a legal and as a practical matter has been made by the Court of Appeals of the Fifth Circuit in *Forest Oil Corporation* v. *F.P.C.*, 263 F. 2nd 622 (1959), wherein the Court said:

> We do not think that either the Commission or the petitioner should be baffled or handicapped in this new field of regulation by any formulas by whatever name they are known. Specifically, if there is an accounting or rate-making formula known to the public utilities industry as a "conventional rate-base method of rate-making" which the Commission in its order of dismissal in this case said must be used at least as a basis of

> comparison or point of departure, we say the Commission need not require it unless such method is the only way by which the Commission can make its required determination. . . . (263 F. 2d 622, 626).

In dealing with the competitive industries such agencies as the Interstate Commerce Commission have found it best to work out regulatory principles based on numerous other standards and criteria. Producer regulation will have to be based on similar considerations. As Justice Jackson stated in his concurring opinion in *Colorado Interstate, supra,* at p. 612:

> ". . . Far-sighted gas-rate regulation will concern itself with the present and the future, rather than with the past, as the rate-base formula does. It will take account of conditions and trends at the source of the supply being regulated. It will use price as a tool to bring goods to the market—to obtain for the public service the needed amount of gas. Once a price is reached that will do that, there is no legal or economic reason to go higher; and any rate above one that will perform this function is unwarranted. If the supply comes from a region where there is such overproduction that owners are ready to sell for less than a fair return on their investment, there is no reason why the public should pay more. On the other hand, if the supply is not too plentiful and the price is not a sufficient incentive to exploit it and fails to bring forth the quantity needed, the price is unwisely low, even if it does square perfectly with somebody's idea of return on a 'rate-base'. The problem, of course, is to know what price level will be adequate to perform this economic function. . . ."

And as the same justice concluded in the *Hope* case, *supra* at page 650:

". . . If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books. . . .

We realize that any decision we make in this and similar cases will be subjected to the lengthy processes of court review. However, in the absence of the appropriate congressional legislation the resultant delay and uncertainty is an unavoidable hazard.

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[Mimeo., p. 13]

REGULATION OF PHILLIPS' PRICES

While we have found that the rate base method is not an effective means of regulating the producers' prices, evidence in this proceeding was presented almost entirely upon the cost basis and, of course, there were no ceiling prices issued by us at the time of the hearing. There was some field price evidence introduced, but if field prices could be employed in arriving at rates for Phillips, the evidence was incomplete and unrepresentative of Phillips' diverse sales. Therefore we shall proceed on the basis of the evidence adduced in this case to reach conclusions, as reasonable, intelligent and logical as possible even though we know and have herein stated the difficulties inherent in determining a cost of service for Phillips using the rate method. This is clearly a lawful way to determine rates for Phillips as illustrated by the *City of Detroit* case,[11] and under the present record is the only possible method, and therefore we shall make every effort to reach a result by this means.

As will be seen from the discussion below of Phillips' cost of service, the difficulties of the rate base method as

[11] *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC), *certiorari* denied, 352 U.S. 829.

applied to independent producers are well illustrated. In a number of instances, particularly with respect to allocations and rate of return, it is extremely difficult to arrive at a reasonable result by any formula or systematic method. A number of factors must be taken into account and a decision must be made without any possibility of precisely weighing the factors although we have the record before us and a general knowledge of the gas producing industry. In reaching our decision on the various points, we are of the opinion that it is perfectly proper for us to consider the complicated factors involved and reach a result on the basis of our discretion and judgment—in fact, there was no other way to proceed—but we think that many times repeated application of these judgment factors to the thousands of producers would not be practical or expeditious regulation, as we have explained at length above. In the present proceeding we are as a matter of law permitted to reach results by this method.

"The process of rate making is essentially empiric. The stuff of the process is fluid and changing—the resultant of factors that must be valued as well as weighed." [12] "Problems may arise . . . which must be solved despite the absence of a relevant general rule. Or the agency may not have had sufficient experience with a particular problem to warrant rigidifying its tentative judgment into a hard and fast rule. Or the problem may be so specialized and varying in nature as to be impossible of capture within the boundaries of a general rule. In those situations, the agency must retain power to deal with the problems on a case-to-case basis if the administrative process is to be effective." [13] "Judgment upon—conflicting engineering and

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[12] *Board of Trade* v. *United States*, 314 U.S. 534, 546.

[13] *S.E.C.* v. *Chenery Corp.*, 332 U.S. 194, 202-203.

economic issues is precisely that which the Commission exists to determine."[14] The Commission may, in fact, form "it's own conclusion without the aid of expert opinions."[15] The problem of the allocation of costs, like the problem of the allocation of service "calls for judgment within the Commission's peculiar and expert competence."[16] When the decision "is the product of administrative experience, appreciation of the complexities of the problem, realization of the statutory policies, and responsible treatment of the uncontested facts", it "is the type of judgment which administrative agencies are best equipped to make and which justifies the use of the administrative process" and it is "an allowable judgment" which the Court "cannot disturb."[17]

Upon arriving at a cost of service based upon the facts in the record and our judgment applied to these facts, we are then faced with the problem of rates. As will be set forth below, we do not think that it is appropriate to set rates for the future on the basis of this record in this hearing that terminated December 18, 1957, utilizing a test year of 1954 or 1956 and are therefore terminating the proceedings under Section 5(a) in Docket No. G-1148, particularly since rates for the future will be subject to the area price standards we are announcing. Since we are finding that Phillips' cost of service on the basis of the test year 1954 exceeds its jurisdictional revenues, and on the basis of other considerations discussed below we are also terminating proceedings under Section 4(e) consolidated herewith.[18]

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[14] *Chapman* v. *F.P.C.*, 345 U.S. 153, 171.

[15] *Market Street R. Co.* v. *Comm'n.*, 324 U.S. 548, 560.

[16] *Michigan Consolidated Gas Co.* v. *F.P.C.*, 203 F. 2d 895 (CA3).

[17] *S.E.C.* v. *Chenery Corp.*, *supra* 332 U.S. at p. 209.

[18] Two of these proceedings, however, will be left pending until the rates of Phillips' customers are finally determined as explained below.

(32656)

We can now turn to the discussion of Phillips' cost of service. Before examining the various items in controversy we may say that we agree with the examiner that 1954 is an appropriate test year for the purposes we have in mind. Phillips had submitted a cost of service study for 1956 which indicated that its jurisdictional cost of service for that year was not very different from 1954. The Southern California Companies contended, however, that Phillips' earnings in 1954, and in 1956 were unrepresentatively low and had requested that a cost of study be submitted on the basis of 1955 operations. The testimony shows that Phillips' higher earnings in 1955 were essentially from operations other than the production of oil, gasoline, and gas. Under these conditions, there would have been little utility in requiring that Phillips submit a third cost of service study, so we shall use 1954 as a test year.

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[Mimeo., p. 15]

EXPENSES

Expenses, except for allocation and tax questions, have not given rise to many controverted issues in this proceeding. We shall defer consideration of the total tax and the tax benefits arising from the statutory tax incentives relating to percentage depletion and I.D.C. until we discuss rate of return. Other expense issues relate to the size of oil and gas exploration expenses, the alleged increase in purchased gas costs, and treatment of certain interest deductions for tax purposes.

As set forth by the examiner, Phillips' total exploration and development expenses for gas and oil, before adding return, amount to $47,474,039. (See Appendix 1). There are included expenses relating to underdeveloped lease rentals, drilling tools, expired and surrendered leases, dry holes and land and geological activities. Return and taxes as computed herein would amount to $10,839,194, making a total

exploration cost of $58,313,233. The Southern California Companies and P.G.&E. contend in their exceptions that Phillips has not met its burden of proof merely by reciting the amount of its exploration expenses during the test year and that such amounts should not be accepted uncritically. The Southern California Companies present figures to show that Phillips' gas reserves have been increasing, that the claimed exploration expenses in the test year 1954 were the highest to that date and that there has been for more than a decade a substantial excess of reserves added over gas produced. They do not object to imposing upon current production, some reasonable portion of current exploration expenditures, but believe that an inquiry should be made as to the extent of the exploration expenditures that should properly be borne by current production. Neither of these parties offers any theory or any criteria for determining how much of the exploration expenses should be included in the cost of service for the test year.

In view of the increasing needs for gas and the increasing costs of obtaining it as shown by the record in this case, we are of the opinion that Phillips' overall exploration costs are reasonable. It is true that Phillips is developing gas reserves at a greater rate than it is producing gas, but the record shows, and it is well known to us, that there is an expanding demand for natural gas. Therefore it is reasonable and prudent for Phillips to develop more reserves each year than it produces. We are of the opinion that Phillips has not shown an excessive tendency in this direction, particularly in view of our treatment of the expenses related to the San Juan reserves sold in place after the test year and are therefore disposed to allow expenses undertaken in the discretion of management to obtain for Phillips adequate reserves to continue its business. It will be noted below that exploration expenses allocated to gas, amount to 3.5 cents per Mcf, which appears to be in line with industry practice.

With respect to purchased gas, Phillips argues that if it is allowed increased rates, its cost of gas will rise automatically under percentage-type casinghead gas contracts with its suppliers, so that it should be

[Mimeo., p. 16]

allowed an anticipated increase in the cost of purchased gas. In the cost of service submitted by Phillips, this particular item would amount to $8,183,917; as the examiner computed a lower cost of service and consequently lower rates, the same item, if it had been allowed by the examiner, would amount to $1,671,733, as computed by Phillips. The examiner was of the opinion that the purchased gas cost adjustment should not be allowed, for no showing had been made that Phillips' suppliers were entitled to an increase. We think, however, that Phillips' exception should be allowed on this point.

The producer of gas selling to Phillips under percentage-type casinghead contracts receives compensation, at least in part, on the basis of a percentage of the proceeds received by Phillips for the gas and extracted liquids sold from its gasoline plants. In other words, the producer's compensation will be measured not by the amount per Mcf of gas, but by a percentage of what Phillips receives, and the rate is fixed by formula rather than so many cents per Mcf. Although Phillips will pay more per Mcf for its purchased gas, if its own revenues from gas sold from its gasoline plants are increased, there is no change in the percentage and there is no rate change on the part of Phillips' suppliers, for which a rate schedule filing must be made. As Phillips points out, conditions other than a change in Phillips' rates could affect the amount that Phillips pays. For instance, variations in the volumes of gas sold to different purchasers may affect the weighted average price per Mcf paid by Phillips, yet it would be unreasonable to consider this a change in rate.

Our regulations recognize the percentage arrangement and do not contemplate that a change in the amount paid the producer, as opposed to the percentage, will require a rate filing. In any case, the producer under such a contract is not privileged to make a rate filing. Under Section 154.91(e), as amended by our Order 190, 21 F.R. 7616, October 4, 1956, where a producer, under a percentage contract, sells gas to the operator of a processing plant, the operator shall make all filings required to cover the sale, including a "list of the producers from whom the natural gas is purchased, showing the percentum of the resale price received by each from such sale of gas." The producer may not file rate schedules or rate changes whether or not filings by the operator have been made. The regulation notes, however, that the producer is "fully subject to applicable provisions of the Natural Gas Act, including sections 5 and 7(b)."

The purpose of this regulation is to avoid multiple rate filings by many producers selling gas to the plant operators, for there would be thousands of contracts involved in the case of a large operator, like Phillips. Such a large number of filings would make the administrative task of regulating the independent producers almost impossible. Our authority to alleviate a similar situation by regulation was upheld in *Sun Oil Co.* v. *F.P.C.*, 256 F. 2d 233 (CA5), *certiorari* denied, 358 U.S. 872. In that case Sun owned a part interest in certain gas producing units in Texas, but was not a signatory to the contract by which the gas was sold. Sun made certain

rate schedule filings but the Commission rescinded or rejected these in accordance with Section 154.91 of the regulations. The court noted the burden that would result from an unmanageable mass of rate schedule filings, and held that the rule making power of the Commission was ample to carry out the provisions of the Act, that no injury had

been shown, and that the sale by the operator under the operating agreement would be treated as a single jurisdictional sale of the unit or leasehold gas production. The present situation arising under the percentage contracts differs somewhat in that no actual sale appears to be made to the operator entrusted with the task of filing the rate schedules, but our regulation dealing with percentage contracts likewise deals with a situation that would otherwise create an administrative burden. Since the producers selling gas to Phillips under percentage contracts will receive more for their gas as a result of changes we make in Phillips' rates without a rate filing, or other action on their part, Phillips will automatically be required to pay more for its gas, and its purchased gas cost must be adjusted accordingly. It may be noted that we are not allowing any increased purchased gas cost as a result of so-called spiral escalation clauses in the contracts of Phillips' suppliers. An increase under such a contract would constitute a change in rate on the part of the supplying producer affected.

It is not possible upon the present record to determine the amount of the purchased gas cost adjustment, for it will depend upon the precise rates in effect for Phillips in the various areas. It is not necessary to make the adjustment for the purposes of this proceeding because we are not determining Phillips' rates for the future and are terminating its Section 4(e) proceedings except for two proceedings left pending for a limited purpose.

Coming to the question of the adjustment for interest deductions for tax purposes, we see that Phillips' actual recorded company-wide interest expenses for 1954 amounted to $9,892,308, but that in computing its income tax allowance, Phillips used an interest deduction of only $5,743,077. Phillips argues that this downward adjustment was justified on the ground that the difference of $6,149,231 represented interest paid in 1954 on an issue of bonds which was

converted to common stock by the end of 1955. Phillips says that without this adjustment, the provision for Federal income taxes in 1954 is understated and therefore unrepresentative. We agree with Phillips on this point.

Ordinarily, of course, we use the actual test year as a basis for determining cost of service, but we make adjustments for known changes occurring after the end of the test year. *Mississippi River Fuel Corp.*, 11 FPC 288, 291, 306; *El Paso Natural Gas Company*, 22 FPC 260, 263, remanded on other grounds as *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567 (5th Cir. 1960). The examiner attempts to show that actual interest expense and the debt ratio for 1954 were not abnormal compared with the years both before and after. Interest expense in 1953 was $8,151,028,

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[Mimeo., p. 18]

$9,892,308 in 1954, $8,069,506 in 1955 and $6,782,565 in 1956, while the debt ratio was 22.4 percent in 1952, 28.6 percent in 1953, 27.7 percent in 1954, 11.6 percent in 1955 and 20.5 percent in 1956. It appears to us from these very figures that interest expense and debt ratio were on the high side in 1954 compared with other years. The issuance of additional debt after 1954 is related to additional assets on which an additional return would be earned, but is not relevant to the test year and must be disregarded. On the other hand, the debt associated with the 1954 assets and rate base was reduced substantially soon after the end of the test year. Thus the downward adjustment of the 1954 interest expense becomes proper in order to normalize the test year. The amount to be deducted would be $1,895,730 when allocated to the Natural Gas Department and the Oil and Gas Production Department on the basis of dollars of consolidated net assets as shown in Appendix 2.

[Mimeo., p. 19]

ALLOCATION OF PRODUCTION COSTS BETWEEN OIL AND GAS

Phillips produces gas alone on certain leases, oil alone on other leases, and both together on still other leases. The purely gas leases are operated by its Natural Gas Department; the oil only and joint products leases are operated by its Oil and Gas Production Department. The determination of the production costs, other than exploration costs, of the dry gas in the Natural Gas Department is, in the case of Phillips, relatively simple; the determination of production costs of gas produced with oil and condensate in the Production Department involves a number of most perplexing problems. For the purpose of allocating joint production costs (exclusive of exploration costs), amounting in all to $65,252,443 including return and tax incentives as set forth in appendix 5, between oil and gas produced from the same wells, a method known as the relative cost method was employed by witnesses for Phillips, the Eastern Companies, and by Wisconsin and was adopted by the examiner. This method allocates the actual costs of joint oil and gas production in proportion to the known costs of producing each product separately. The staff, on the other hand, used an imputed cost method, supported by a sales realization method, but this was rejected by the examiner.

We agree with the examiner that the imputed cost method does not constitute a satisfactory basis for the determination of the cost of Phillips' casinghead and condensate gas produced in the Oil and Gas Production Department. The imputed cost method does not allocate Phillips' total costs. It merely assumes that the unit cost of the casinghead and condensate gas is the same as the unit cost derived from dry gas produced in the Panhandle-Hugoton Field without using or reflecting the actual total costs of the joint product

wells. Furthermore, it appears that the dry gas costs in the shallow Panhandle and Hugoton fields were the lowest gas production costs on the Phillips System.

As the examiner states, the relative cost method is particularly suitable for allocating the joint production costs of a company such as Phillips where the number of leases and the geographical spread of operations provide a broad base for determining the unit costs of the separate products exclusive of exploration. Under the relative cost method a unit cost for dry gas is determined from the records of Phillips' Natural Gas Department; a unit cost for oil is obtained from the records of Phillips' Production Department relating to 100 percent oil leases and as a result of the allocation of indirect expenses between the 100 percent oil leases and the joint product leases. These unit costs for the two products are multiplied by the volumes of oil and gas produced on the joint product leases. This provides a tentative total relative cost for the oil and gas produced from such leases and a ratio of tentative gas cost to tentative total cost. This ratio is then applied to the total cost of the joint product leases to obtain the cost of the jointly produced gas. (See Appendix 5)

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[Mimeo., p. 20]

In applying the relative cost method, Phillips divided production costs into: (1) direct expenses, including depletion, depreciation, and amortization which are shown in the records by leases, (2) indirect expenses, which must be allocated to leases and (3) return and taxes, based on investment identifiable by leases. This classification appears to be appropriate and we have utilized it in the computations set forth in Appendix 5. The indirect expenses amounting in all to $20,106,343 may properly be divided into *direct general expense* and *indirect overhead*.[19] The *direct general expense*

[19] The examiner uses the term general company overhead for this item (Mimeo, p. 49).

item includes expenses as salaries of management, thrift plan expense related to the salaries, employee's retirement and insurance expenses, vacation expense and bad debt expense. These expenses relate principally to the Oil and Gas Production Department, but also to the Natural Gas Department, gathering system and gasoline facilities, and the residue gas system (see Appendix 1). The examiner included with *direct general expense* relating to the Oil and Gas Department, such items as developmental dry hole expense, lease rental expense, expired and surrendered leases and certain developmental land and geological expense to form an item called departmental general expense of the Oil and Gas Department which he allocated between the 100 percent oil leases and the joint product leases in that department. We are of the opinion that all exploration and development items are so closely related that they should be allocated together and apart from the production expenses with which we are concerned here. It is often a difficult matter to separate developmental expenditures from purely exploration expenses. For instance, it is not always possible to tell whether a well is drilled to develop an established field or to discover a new source of gas or oil, and many dry wells are drilled in areas where oil has been proven. All wells are, in a sense, exploratory.

The *indirect overhead* consists of Phillips' top-level company-wide management expenses, such as salaries and related items. It is actually composed of expenses similar to those found in direct general expense but at a higher level in the corporate hierarchy.

Turning to the method of allocation, we find that Phillips allocated the *indirect overhead* by first determining the portion of this item to be assigned to the Natural Gas Department and the Oil and Gas Production Department on the basis of net capital employed. There was no dispute about this method and we shall employ it here as set forth in

Appendix 1. Phillips then distributed the portion allocated to the Oil and Gas Department between the 100 percent oil leases and the joint product leases on the basis of net investment, and the examiner acquiesced in this method for the indirect overhead. This step was necessary, as indicated above, in order to separate those costs dealing with oil and to obtain a unit cost for oil which could be used to determine the separate oil and gas costs of the joint product leases.

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[Mimeo., p. 21]

We, however, are of the opinion that the distribution should have been made on the basis of direct operating expenses.[20] Management's function is concerned with the direct operation of the business in any particular year. It is concerned with all expenditures, not just with investment. No relationship has been shown between investment in the property and the amount of time spent by management in supervising the various activities of the company.

A similiar problem arises with respect to the distribution of the *direct general expense* of the Oil and Gas Department as discussed at some length by the examiner. This item, as stated above, also consists largely of salaries, and should properly be distributed between the 100 percent oil leases and the joint product leases on the basis of direct operating expenses. In allocating this item along with developmental dry hole expense as "departmental general expense" the examiner employed the gross investment method while Phillips, in its exceptions, said he should have used the net investment method. Since the items relating to lease investment have been transferred to exploration and develop-

[20] Actually the difference between the two methods is relatiely insignificant in result. Phillips allocates the $7,622,773 of Oil and Gas Department indirect overhead $1,675,853 to the 100 percent oil leases and $5,946,920 to the joint product leases while our distribution of the same amount is $2,385,318 to the 100 percent oil leases and $5,237,455 to the joint product leases.

ment expense and allocated as such, the principal basis of employing an investment method, either net or gross, has disappeared, and the allocation of the management items should be carried out on the basis of direct operating expenses.

In applying the relative cost method to allocate the joint production costs the question arises whether a credit should be given to gas for its use in lifting the oil. Testimony in the record showed that gas enables the recovery of a greater amount of oil from a pool than would otherwise be possible. It does this by reducing surface tension, viscosity, and specific gravity and by providing a source of energy which moves the oil through the formation to the well bore and thence to the surface of the ground. Phillips presented evidence that only the gas content up to 300 cubic feet per barrel of oil contributes to the recovery of oil. The record does not finally resolve this question nor does it provide a way of computing the credit for any supposed lifting effect of the gas. In fact, we think that it would be almost impossible to compute the value of the lifting effect of gas in oil production. Furthermore, it can be said that the lifting effect of gas is not so much a reason to give a credit to gas, but reason to increase the value of gas for lifting oil is a very valuable use for gas.

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[Mimeo., p. 22]

As Phillips points out, the 100 percent oil leases, which do not have the benefit of the gas lift, appear to represent a higher unit cost of oil production than the joint product leases, while dry gas leases represent a lower cost of gas production than the joint product leases. Thus when the relative cost method is applied to Phillips, this factor tends to shift costs to oil compensating the gas for the lifting effect, if present. Therefore, we do not see any necessity in this proceeding in crediting gas costs with a possible serv-

ice to oil production, particularly in view of the inadequacy of the record.

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[Mimeo., p. 23]

ALLOCATION OF EXPLORATION COSTS

Like independent producers generally Phillips incurs substantial costs for exploration and development for the purpose of maintaining its oil and gas reserves. These exploration and development costs are not directly associated with successful wells whose costs are accounted for as investment and in this proceeding are included in the rate base;[21] these costs do include the costs of unsuccessful exploration and, under the practices of the industry, are included in current expenses. There is no dispute as to the necessity for including an allowance for such costs in Phillips' cost of service, but there is considerable dispute as to their allocation between oil and gas.

Total exploration and development expenses before return amount to $47,474,039 and return and taxes on exploration investment as computed herein amounts to $10,839,194, making total exploration costs of $58,313,233 as discussed above and as set forth in Appendices 1 and 7.[22] The problem before us is how to divide these exploration costs between the production of gas on the one hand and oil on the other.[23] While a portion of the exploration costs can be attributed

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[21] Intangible well drilling and development costs are expensed for tax purposes as discussed below.

[22] As explained above, page 20, the examiner included as departmental general expense of the Oil and Gas Production Department, certain developmental dry hole expense ($4,521,943), lease rental expense ($163,716), expired and surrendered leases ($24,750) and developmental land, geological and geophysical expense ($1,699,037) but we combine them with the similar costs of the Natural Gas Department in exploration costs and allocate the combined amounts.

[23] Gas in this section includes vapors subsequently removed as liquids in gasoline plants; the allocation of cost between dry gas and extracted liquids is discussed in the following section.

directly to Phillips' Natural Gas Department and were so recorded, the greater part are joint costs for which some technique of allocation is necessary. We feel, as explained below, that it is appropriate and in the public interest that we deal with the allocation of Phillips' test year exploration costs as an allocation of joint costs between co-products with each required to bear its proper share of the joint costs in the light of all of the circumstances that affect the incurrence of the joint costs.

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[Mimeo., p. 24]

Ideally we would like to find some characteristic of gas on the one hand and oil on the other that would provide a simple and logical basis for allocating Phillip's exploration costs. No such characteristic has been shown to us, nor have we been able to discover any such characteristic of the respective products or any one method of allocation which will satisfactorily form a basis of allocation. What we are striving to do is to reflect not only the market demand for the two products, and the amount of physical material acquired, but also the trend of economic events by which there now appears to be a market glut for oil, but a continuous and expanding demand for gas. As a guide to final judgment it is extremely useful to examine the various methods of allocation presented in this proceeding and the results reached.

We find that Phillips, itself, employed what may be termed net leasehold investment—Btu method. By this method Phillips proposed, first to divide exploration costs between its Natural Gas Department and its Oil and Gas Production Department in proportion to net investment in producing leaseholds. Of the amounts so allocated to departments, a portion was first allocated to royalties owned by Phillips, in the amount of $2,393,368, using the same basis. Then costs were allocated between oil and gas in the Production Department in proportion to test year Btu pro-

duction of each product.[24] The exploration costs allocated to gas in the Natural Gas Department were added to the amount allocated to gas in the Production Department. Under this method, on the basis of Phillip's computation, 61.88 percent of exploration costs were allocated to gas. Phillips argued that the net leasehold investment method would reflect its experience and the fact that exploration is basically a search for reserves, and supports the Btu approach by saying that oil and gas exploration is a search for energy.

The Btu method undoubtedly has some justification and considerable appeal because of its simplicity and convenience. Exploration operations are frequently undertaken without clear knowledge of whether gas or oil, or both, will be found. Thus when either or both of these products are found it is difficult to ascribe the purpose of the exploration wholly to the respective market values of the products, so that there is considerable logic in comparing the products upon the basis of a common physical characteristic. On the other hand, such a method reflects only in part the potentialities of the hydrocarbon products. Oil and gas are not produced, purchased and used merely on the basis of Btu content or available energy. The transportation, refining, distribution and utilization factors are equal to or greater than the factors of exploration and development. As the examiner explains, the chief function of the oil industry is to provide fuel for transportation. Oil and its component, gasoline, are basically useful because they provide energy in compact, mobile and easily controlled liquid form.

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[Mimeo., p. 25]

Actually, the heavier the crude oil, the higher will be its Btu content but the lower will be its gasoline content and

[24] A Btu (British Thermal Unit) measures the heating value of the product. It is the amount of heat required to raise one pound of water one degree fahrenheit.

its price. Gas, on the other hand does not have the mobility of oil, for it must be carried in pipelines under pressure and used under limited conditions. Both oil and gas are used for the manufacture of chemicals and plastics which could not be properly compared on the basis of Btu. Thus if the Btu method is to be made practicable and useful for the allocation of costs it must be modified by the exercise of judgment based on the facts and the principles that guide producers in the incurrence of costs. Such a modification is carried out below.

The Eastern Companies advocated a method of allocation known as the "Reserves Added Realization Method" (RAR). Under this method, exploration costs were allocated on the basis of the ratio of the reserves of natural gas and natural gas liquids retained by Phillips to the present value of all additions to reserves of all products during the selected base period, whether sold or retained. The method thus makes an automatic adjustment for the large amount of reserves in the San Juan Basin sold to Pacific Northwest Pipeline Corporation in 1955. In applying this method which was adopted with certain modifications in the computation by the examiner, the Eastern Companies used the base period of 1951-1955 and a price for natural gas of 13.47 cents per Mcf, which represented the weighted average price paid by interstate pipelines for gas delivered in 1956 under new contracts in the Panhandle-Hugoton, West Texas, Permian Basin and Gulf Coast areas. For natural gas liquids they used Phillips' 1956 average sales realization of $1.587 per barrel and for crude oil and condensate the first half of 1957 average mid-continent price quotation of $3.07 per barrel. On the theory that the deliveries form these reserves would be made over an extended period, they applied an escalation of two cents every five years for the gas and a discount period of 20 years for the gas and 10 years for the oil at a discount rate of 6 percent. The exam-

iner adopted this computation of escalation and discount. The result of this method, as employed by the Eastern Companies and the examiner, is to allocate 30.46 percent of the exploration costs to gas.

RAR has the advantage of basing the allocation on the objective of exploration, that is the reserves acquired, and arrives at a result which, as will be seen, lies between the extremes represented by other methods and does not appear unreasonable, but it has severe disadvantages. Thus RAR results in the unregulated prices of natural gas liquids and oil influencing our determination of the cost of gas and therefore the rate which we would allow for gas. RAR is dependent on market prices; as regulation of the producers proceeds, the use of RAR in future proceedings would be dependent in part on regulated prices that will be used in part to determine regulated prices. RAR is rooted in the theory that there is an association of unsuccessful exploration costs with the result of successful drilling during a given period, but this is inconsistent with the accounting for exploratory losses and costs as current items and could yield unreasonable results over a limited period. Furthermore, RAR has a

very serious administrative disadvantages in that it is very difficult to estimate the size of the gas and oil reserves of a producer. Experience has shown that experts differ substantially as to the size and deliverability of the reserves. furthermore, the estimates are inherently subject to periodic change as a result of experience with the lease or field involved. Therefore, we are of the opinion that while the results may not be substantially unreasonable in this case, RAR is not a satisfactory or workable method of allocating exploration costs.

The witness for the Eastern Companies among other methods, also computed an allocation of exploration costs to gas on the basis of sales realization. This means that the allocation would be made on the basis of the revenues from the respective products during the test period. The result of this method would be to allocate 20.7 percent of allocation costs to gas and 79.2 percent to oil. When the sale of reserves is considered, 16.9 percent of exploration costs would be assigned to gas, 64.5 percent to oil and 18.6 to the sale of reserves. The sales realization method has the advantage of reflecting the market demand for the products, an important factor to be taken into consideration. It is, of course, subject to the same disadvantages as RAR in its dependence on unregulated prices for oil and natural gas liquids, and, in the case of future proceedings, in its dependence in part on regulated prices.

Several other methods of allocation presented in these proceedings depend in part on the sales realization method. The successful wells method, presented by witness for Southern, divides the cost of the dry holes between oil and gas in the same proportion as Phillips' successful wells. In employing this method, it was necessary to use sales realization to allocate the joint-product wells. The result of this method was to allocate 25.8 percent of exploration costs to gas. We agree with the examiner that the method is founded on a mythical ratio which reflects merely the relative number of dry holes placed in the gas or oil categories and neglects other factors. The method advocated by Consolidated Edison divides exploration costs between Phillips' departments on the basis of depletion expense followed by use of a conventional sales realization method based on gross revenue data to allocate Production Department exploration costs between oil and gas. The Pacific Companies employed a net contribution to earnings method which was based upon net revenues determined, in

part, by the sales realization method, and resulted in allocating 23.98 percent of the exploration costs to gas.

The witness for Wisconsin employed a net revenue method. He first determined gross revenues to be used for each of the categories of crude oil, oil from joint-product leases, gas from joint-product leases, dry gas, royalties owned operations, and cycling operations. For his gross revenue figure for gas he employed the ultimate total cost-of-service which he computed for that product. From such gross revenues he deducted total operating costs for each category and made his allocation on the basis of the net revenue figures. In order to carry out this method, it was thus

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[Mimeo., p. 27]

necessary to use the final result in order to perform an intermediate step, the allocation of exploration costs. The testimony indicated that this would involve complicated computations which were not set forth in the record. This method, which allocated 20.8 percent of exploration costs to gas, appears to us to be circular, unduly complicated and not supported by the record.

As can be seen, there is some merit to each of the allocation methods advanced by the parties, but they all have their defects. At one end of the scale can be found the sales realization methods with their emphasis on market and at the other end the Btu method with its attempt to equate oil and gas from the physical standpoint and to avoid the effect of market swings in price, particularly the price of an unregulated product. In view of the advantages of the various methods we are unable to arrive at a rigid formula for the allocation of exploration costs, nor do we think it would be desirable to do so. The relationship of gas prices and oil prices, the relationship of gas to oil in the corporate economy and other factors will differ from case to case, so that

an equitable allocation must vary in order to reflect the place that gas and oil hold in each producer's exploration program.

In making this allocation, we are confronted with the fact that substantial exploration expenditures must be generated through current revenues in order that oil and gas reserves can be discovered in sufficient volumes to maintain service and economic stability of the industry. In other words, the gas consumer must pay rates sufficient, among other things, not only to amortize the cost of the successful past drilling which makes present service possible, but also the current losses and other expenditures incurred in an attempt to replace the gas currently being produced and consumed and continue service in the future. This objective is important socially and militates against a formula for the allocation of exploration costs. However, we are not entirely without the guidance provided by the fuel value of the various products, market factors and economic trends.

None of the parties challenge the fundamental fact that it is the Btu content of fuels that makes them useful to consumers. The argument has been in regard to the importance to be accorded such energy contents of oil and gas in regard to the allocation of their joint exploration costs, and conversely what importance should be accorded the economic factors that producers consider in incurring such costs, and which affect the sale of oil and gas in the fields in different fashions. It is well known in the producing industry that it frequently is impossible to predict whether gas or oil will be found, although certain areas are more favorable for finding gas and other areas more favorable for finding crude oil. To this extent exploration cannot be entirely responsive to market price and it becomes reasonable to allocate the cost of the operation on a physical basis. On the other hand, exploratory activities are directed to obtaining saleable products so that it seems reasonable that market relationships

should also be reflected in the allocation. Furthermore, developmental activities are directed towards the production of known reserves and such activities would reflect market conditions. We must also take into

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[Mimeo., p. 28]

account that there is a continuous and expanding demand for gas while the market for domestic produced crude oil and its components is also growing, but at a slower rate.

Historically, much of the jointly produced casinghead gas was produced as a waste by-product from the production of crude oil, and no avoidable costs were incurred either for its exploration or production. Later, with improvements in conservation, gathering and processing costs became justifield to save the gas for field uses and these were considered the only costs chargeable to this gas. Now with a growing appreciation of this gas as a fuel supply for distant consumers, it is considered a co-product of crude oil in exploration as well as production. Much of such gas production now serves first as an aid to recover additional oil and gas liquids and after this, becomes available to distant gas consumers for the same uses as naturally dry gas. The output of this gas has mounted with the output of crude oil. This type of gas has, therefore, now become an integral part both of the producers joint exploration and production activities and contributes substantially to the total gas supply.

Deeper drilling in recent years has also discovered increasing proportions of gas to liquids. The contents of some of the recently developed gas-condensate reservoirs exist wholly in the gas phase; and a portion of the gas condenses naturally during the production process into a liquid that is separated and sold as light crude oil. In such instances, conservation of these liquids has sometimes required that after recovering the liquids from the gas, some or all of the gas be cycled or returned to the reservoir temporarily to main-

tain the reservoir pressure, and prevent condensation and loss of the liquids in the reservoir. In areas where these types of reservoirs are likely to occur, equal consideration is given to both products in conducting exploration as well as recovery. Phillips has also shown that over a period of years this changing pattern of production and conservation has entailed increases in the joint production investment costs per unit of output.

Because of the industry tendencies that have developed, we deem it appropriate that in allocating the joint exploratory costs and development losses of Phillips, we shall give increased consideration to the Btu's in gas as a fuel as compared with oil and not confine ourselves entirely to a relationship based solely on recent historical relative values or relative production costs. The allocation method adopted, must also encourage the exploration and development of gas as compared with oil. Furthermore, we must take into consideration that the demand for gas is increasing at a more rapid rate than that for oil, and exploration and development activities are planned and costs must be incurred some time ahead of actual production.

In dealing with exploration costs, it is appropriate that the changing outputs of each product should bear the changing exploration costs in proportion to the contribution that such costs make to each supply, and it

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[Mimeo., p. 29]

is necessary for currently produced gas to bear an increased proportion of the joint exploration costs and development leases if the growing gas demands are to be supplied on a continuing basis. Our purpose, as in past proceedings, is to require that each class of customers bear its proper share of

the cost.[25] Furthermore, in this proceeding we have the particular problem, apart from the traditional methods of allocation based upon past experience, of providing Phillips with sufficient funds for future exploration and production. This is a problem whose solution must depend not only upon costs but on the exercise of judgment. In the *Colorado Interstate* case, the Supreme Court said "Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science." (324 U.S. at p. 589).

Expressing all of the factors quantitatively, we find that when we take the Btu content of a standard measure of gas, an Mcf, and compare it with the Btu content of a standard measure of oil, a barrel[26] the ratio of gas to oil is about one to six.[27] However, on the basis of Phillips' prices in the field, the ratio is about one to 33 for the year 1954. We can conveniently apply a factor to the Btu ratio that will have the effect of correcting its unreality and of avoiding imposing costs on gas consumers which should fairly be borne by the consumers of the ultimate products of the crude oil but also require gas to bear its proper share of the costs. Upon the basis of the considerations expressed above, and the record in this proceeding, we are of the opinion that the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs is four, so that the cost relationship of finding one Mcf of gas to one barrel of oil will be about one to 24.

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[25] See *Atlantic Seaboard Corp., et al.*, 11 FPC 43, 53; *Canadian River Gas Co.*, 3 FPC 32, 61, affirmed as *Colorado Interstate Gas Co.* v. *F.P.C.*, 324 U.S. 581, 586; *Cities Service Gas Co.*, 3 FPC 459, 485, affirmed *Cities Service Gas Co.* v. *F.P.C.*, 155 F. 2d 694, 704 (CA 10), *certiorari denied*, 329 U.S. 773.

[26] 42 gallons.

[27] The actual ratio ranges from 1 to 5.5 to 1 to 6, depending upon the Btu content of the particular oil and gas involved.

Our result is reached by an exercise of administrative judgment applied to the facts of the record as discussed above, p. 13, in connection with *S.E.C.* v. *Chenery Corp.*, 332 U.S. 194. We have made a determination on the basis of the record, which, however, did not lead us to the precise conclusion. However, we are of the opinion that our allocation factor is as well, if not better, supported than our *Seaboard* rule that fixed costs should be classified fifty percent to the commodity charge and fifty percent to the demand charge.

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[Mimeo., p. 30]

Our result might be different in other proceedings under different circumstances. In this case we are not determining rates for the future but are terminating proceedings not only with respect to the future but also, with two limited exceptions, for the past periods involved in the twelve Section 4(e) dockets here consolidated. In determining rates for the future we might arrive at a somewhat different result upon weighing the factors discussed here.

As may be observed, our result differs from the one to 33 ratio that would be obtained from the use of Phillips' test year sales realizations alone. It also differs from the approximately one to 34 ratio that would be obtained using the relative production costs alone. We do not reach our conclusion by modifying either production costs or sales realization, but rather by modifying the fundamental Btu relationship, because it is the Btu content that is the fundamental quality of fuels. Thus this economic factor is applied to the Btu or common fuel value of oil produced by Phillips to relate its Btu's to the joint exploration costs in the light of all of the circumstances developed in the record. The ratio we adopt to allocate Phillips' exploration costs thus gives more consideration to the relative Btu contents than does the relative test year realizations, or relative production costs, gives effect to the upward trend of gas production

relative to oil in relation to the present level of exploration costs, and recognizes the increasing contribution that Phillips' current exploration costs are making to gas supplies as compared with oil. We believe that using such a ratio, and also fixing all gas rates on the basis of costs thus obtained will be of great benefit to consumers and producers alike. We consider the problem of bringing gas to market so important that we have not confined ourselves to a method that considers only historical relationships for the gas currently produced and leaves unresolved the cost basis for determining the rates for the additional gas that customers are demanding now, or will need in the future.

The adjustment factor of 4 which we have applied to the Btu ratio of oil to gas, while based on judgment taking the above factors into consideration, is confirmed by the actual trend of prices. The record shows that the ratio of the price of a barrel of petroleum to an Mcf of gas at the well head produced by Phillips ranged from 39 to 1 in 1952 and 33 to 1 in 1954, down to about 29 to 1 in 1956. If this trend were extended, the ratio would reach our 24 to 1 in 1958. Similarly, the record shows that nation-wide the same ratio was 32.5 to 1 in 1952 and 27 to 1 in 1954. We may take notice that as shown by figures published by the Bureau of Mines, this trend, with certain ups and downs, continued, reaching 25.3 to 1 in 1958 and, if extended, would have reached a ratio of around 23 to 1 in 1959.

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[Mimeo., p. 31]

In carrying out the computation (as set forth in Appendix 6), we use an allowance for the Btu's in the Mcf of gas ranging from 1025 for the dry gas and San Juan gas to 1250 for the casinghead gas, while we use an allowance of 5800 Btu's for a barrel of oil and 5500 Btu's for a barrel of condensate. After computing the total amount of Btu's for the various types of gas and for oil and condensate based on

volumes and employing the factor or four discussed above, we allocate $47,474,039 of exploration and development expenses 32.742 percent to gas and 67.258 percent to liquids. This amounts to 3.485 cents per Mcf of gas and 73.71 cents per barrel of liquids. We then allocate return and taxes amounting to $10,839,194 on exploration and development investment between gas and liquids on the basis of the same percentages. The total exploration and development cost, including return for gas become. 4.281 cents, while it amounts to 90.54 cents for liquids. The gas here includes condensate gas from which other liquids will be removed in the gasoline plants resulting in a further allocation of cost to liquids. The 4.281 cents per Mcf figure that we have reached for gas is a reasonable allowance for exploration and development based upon our knowledge of other companies in the industry. However, it will vary from company to company depending upon the relative amounts of the gas and liguids produced, the levels of output, the results of its exploration and the areas in which it operates.

In making our allocation of exploration and development costs, an adjustment was made for the proven gas reserves owned by Phillips in the San Juan Basin during the test year 1954 but sold in place to Pacific Northwest in 1955 with an overriding royalty retained. In making this adjustment, it was assumed that exploration and development costs in the test year were associated with production from the San Juan Basin as well as with production from Phillips, properties retained. Phillips, itself admits,[28] that the San Juan royalties, of course, must bear some portion of current exploration expenses. What we have done is to normalize the gas royalty production of the San Juan Basin upward to reflect the normal recurring royalty production in subsequent years. Our treatment is consistent with the treatment

[28] Brief, p. 127.

of additional expenses arising from wage increases and our general policy of giving effect to known operating charges occuring within a reasonably short time after the close of the test year.

Although the actual production from the San Juan Basin during the test year was small, it was assumed that the volumes would be produced over an estimated life of 20 years, or 60,750,000 Mcf per year. Such a production period for gas wells is supported by the record and is consistent with our general requirements for gas supplies prerequisite for granting certificates. Our computation results in allocating $2,278,279 of exploration and development expenses to the San Juan gas, making a total of $2,452,98? allocated to royalties compared with the examiner's $7,558,299.

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[Mimeo., p. 32]

ALLOCATION OF COSTS BETWEEN NATURAL GAS AND EXTRACTED LIQUIDS

As the examiner shows, Phillips sells residue gas and certain liquids, including gasoline, from the gasoline plants which it owns in the various fields. The question arises as to how to treat these sales in relation to cost of service. The first question is whether the gasoline plant operations should be considered jurisdictional, in which case the gasoline plant costs and revenues would have to be reflected in the jurisdictional gas cost of service, or whether the gasoline plant operations should be considered non-jurisdictional, in which case some method is necessary for allocating costs between the liquids separated in the gasoline plants and the residue gas. We are of the opinion that the examiner was correct in concluding that the gasoline plant operations are non-jurisdictional. The examiner goes into this matter thoroughly and his presentation, which we adopt, need not be repeated here. The record shows that the gasoline plant operations constitute a business for the benefit of Phillips

rather than for the purpose of rendering the gas fit for pipeline transportation. The present situation differs from that involved in the *City of Detroit* case,[29] where the court held that the extraction operations were clearly within the jurisdiction of the Commission. In that case, Panhandle Eastern Pipe Line Company was both a producer and a pipeline company, and the court was impressed with the Commission's finding that the extraction of the heavier hydrocarbons did improve the efficiency of Panhandle's pipeline system along with the fact that the extraction process was incidental to the over-all pipeline transmission and resale operations. Here, on the other hand, Phillips is an independent producer without a pipeline system selling various products, oil, residue gas, gasoline etc. The production of gasoline and other liquids in the gasoline plants is not a mere incident to the sale of gas. It is an independent business, which is not subject to our regulation. There is thus only a question of the proper method of allocating costs to the separate products.

Our problem then, is to take the raw gas as it enters the gasoline plants with the exploration costs and the production costs assigned to it and determine what portion of the costs adherent to the raw gas is applicable to the residue gas leaving the gasoline plants. A number of methods to accomplish this were presented. A witness for the staff employed a relative value method which depended upon a market value for the gasoline and the gross realization from the sale of the residue gas. Wisconsin's witness presented what was known as the single marketable product method, in which he assumed in turn that the gas and then the liquids were waste products and obtained a justifiable cost of residue gas and a justifiable cost of liquids at the tail gate of the gasoline plants. In arriving at the justifiable cost of liquids, he substituted actual revenues as the

[29] *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC), certiorari denied 352 U.S. 829.

measure of their cost on the ground that the liquid revenues were lower than the combined cost of gas and liquids when assuming gas was a waste product. He eventually constructed a ratio of the justifiable cost of residue gas to the sum of the justifiable cost of residue gas plus the justifiable cost of natural gas liquids with a net result of allocating 28.40 percent of the costs to liquids and 71.60 percent to gas, based thus on all costs to the tail gate of the plants.

The witness for the Eastern Companies used a sales realization method, modified by adjusting downward the book revenues for natural gas liquids so as to eliminate plant processing costs and by adjusting upward Phillips' revenues from residue gas so as to reflect the same 1956 new contracts average price of 13.47 cents which he had used for the allocation of exploration costs under the RAR method. The examiner followed the sales realization method recommended by the Eastern Companies. However, he concluded that it should be corrected so as to exclude return and related taxes on gasoline plant investment in addition to plant processing costs. He reasoned that the price of the residue gas truly represents the value of the residue gas in the wet gas stream, but that in the case of the liquids, the price is substantially affected by the gasoline plant processing operation so that total gasoline plant costs should be deducted, including taxes and return. As modified by the presiding examiner, the sales realization method resulted in allocating 16.7881 percent of the raw gas costs to liquids.

Phillips employed a Btu method. It charged the investment and operating costs of the gasoline plants wholly to the liquids. There was thus left for allocation only the joint costs of the raw gas stream at the inlet of the plants. Phillips performed this allocation in steps by what it called the volumetric Btu method. In the first step, an allocation of costs was made on the basis of the volumes of residue gas de-

livered by the plant compared with the reduction in the volume of the raw gas resulting from the returns of gas to the leases and the extraction of the liquids. In a second step, the allocation was adjusted to account for the loss of heating content in the residue gas as compared with the raw gas. Both reductions result in allocating 16.7202 of the relevant joint costs of the raw gas to liquids.

We are of the opinion that the Btu method is appropriate and simple for the allocation of costs to the products of the raw gas stream, and that it will not be necessary to bring in the factor of market price as we did in connection with exploration costs. We agree with the examiner that the single marketable product method of Wisconsin, which also makes use of revenues dependent on market prices, is highly artificial in addition to being subject to the defects of the realization methods. In support of the Btu method, we note first, that all of the products of the raw gas stream are in a gaseous state when entering the gasoline plants, so that the situation is different from that we face in allocating costs between oil and gas. Secondly, the extraction of these liquids reduces both the volume of gas and its Btu content. Furthermore, Btu measures a significant characteristic common to all of the components of the raw gas stream, that is the ability to produce energy. Oil, more than the natural gas liquids, has many uses other than fuel,

and so, as we have said, is not adaptable to a straight Btu method. By making cost allocated to residue gas dependent on Btu content, the operator of gasoline plants will not remove hydrocarbons from the gas stream unless they would interfere with the transportation of the gas or unless they would command a price out of all proportion to their Btu content when left in the gas stream. Unnecessary and costly removal of products from the raw gas will thus be avoided.

The Btu method is useful and simple for our present purposes, and it reaches a reasonable result, not very different, as will be seen, from that reached by the examiner on the basis of his modification of the sales realization method.

As noted, Phillips carried out the Btu method in steps. What it did was to reduce the total volume of gas gathered, 687,145,852 Mcf by the raw gas sold from the system, 18,845,896 Mcf, a reduction of approximately 2.7 percent. It then reduced the balance of raw gas, 654,863,239 Mcf by the loss in the gasoline plants due to the extraction of the liquids and the return of gas to leases, a reduction of some 9.5 percent. Phillips applied the 2.7 percent to the total raw gas costs[30] in order to allocate costs to raw gas sold. It also applied the 9.5 percent to the total raw gas costs to obtain an allocation of costs to liquids. We think that the 9.5 percent should have been applied to the costs, rather, of the gas remaining after the sale of the raw gas, for that is the way the 9.5 percent was derived.

Phillips then computed a percentage reduction in Btu content per Mcf from raw gas to residue gas amounting to about 7.6 percent.[31] It applied the 7.6 percent to the balance of raw gas costs after the deduction of the 2.7 percent and the 9.5 percent. The 7.6 percent represented an addition to the liquids cost, and the balance represented cost of the residue gas. As a final step, Phillips added back the costs allocated to raw gas sold to obtain a total cost of system sales, $95,329,193, which it allocated on a volumetric basis 28 percent to non-jurisdictional sales and 72 percent to jurisdictional system sales.

Apart from the error that we believe Phillips made, we think that this step method is unduly complicated and with-

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30 Gas purchases, lease production—cost of service, and gathering system—cost of service.

31 Btu content of inlet gas was 1151 Btu and of residue gas was 1063 Btu 1151—1063=88; 88÷1151=7.6 percent.

out any necessary logical foundation. The allocation of raw gas costs to extracted liquids, raw gas sold and residue gas can be performed more simply on the basis of aggregate Btu.

32677

[Mimeo., p. 35]

The computation is performed in Appendix 9. This shows the total gas produced and purchased amounted to 783,675,122 Mcf. This is divided on the basis of volumes into field sales and total gas gathered, the latter amounting to 687,145,852 Mcf. The total gas gathered on the basis of volumes is distributed to raw gas sales in the amount of 18,845,896 Mcf and residue gas sales amounting to 592,282,042 Mcf, leaving 76,017,914 Mcf representing returns of gas to leases and the loss in volume resulting from the extraction of the liquids, etc. These amounts are then converted to Btu's using the 1151 Btu's per Mcf for the gathered gas and raw gas sales and 1063 Btu's per Mcf for the residue gas. From the Btu figures obtained percentages are derived, showing that of the total gas gathered, 17.6529 percent is allocable to extraction losses and returns to leases and 79.6045 percent to the residue gas sales. In the computation of the cost of service to be discussed below and shown in Appendix 10, the total cost of produced and purchased gas is reduced by the 17.6529 percent, representing the extraction liquids and returns to leases.

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[Mimeo., p. 36]

RATE BASE

The examiner used a 1954 year-end rate base, while the staff, Wisconsin, the Southern California Companies, and the Michigan Commission excepted, saying an average rate base should have been used. In past cases dealing with pipelines and electric companies we have traditionally used the average rate base although we have indicated that we might

consider the year end balances in a proper case. *United Fuel Gas Company*, 12 FPC 251, 255; *Otter Tail Power Company*, 8 FPC 393, 400-401. The examiner has pointed to evidence showing that over a period of years Phillips' investment has been steadily increasing presumably, in part, because of the increasing costs of drilling for gas. In a company with such a rapidly expanding need for investment, we are of the opinion that the average test year rate base is not as representative of succeeding years as the year-end test year rate base, and therefore we agree with the examiner that year-end should be used. This does not mean that we shall not ordinarily require the average rate base in electric and pipeline rate cases.

In its exceptions, the staff objected to the inclusion in the rate base of $17,765,332, representing undeveloped offshore leases, title to which was held by a subsidiary of Phillips during the test year. The subsidiary was dissolved in 1955 and the offshore leases were transferred to Phillips. The testimony indicated that, upon investigation, Phillips decided that the leases should be owned by the parent company. We have no difficulty in agreeing with the examiner that Phillips and its subsidiary should be treated together. In view of the necessity that all producers acquire additional reserves, we think that these reserves should be properly included in its rate base even though there was no production from them during the test year in the absence of a showing that holding these reserves without producing gas from them was unwarranted. In another proceeding where the record shows that leases owned by the producer had been developed but were being held without producing, it might be reasonable to exclude them from the rate base. For similar reasons, we agree that the examiner properly included in the rate base additional undeveloped leases, which with the offshore leases, totalled $76,347,908 in the test year 1954.

(32678)

A somewhat different problem is presented by the inclusion in the rate base of $8,430,758, representing net investment in the San Juan producing leases which were transferred to Pacific Northwest Pipeline Corporation in November of 1955. Wisconsin and the Southern California Companies both exempt to the examiner's inclusion of this item. They argue variously that the jurisdictional revenues received from the properties during the test year amounted to only $141,968 and that the revenues received from Pacific Northwest would be considered part of Phillips' non-jurisdictional business. We are of the opinion, however, that the examiner was correct in the position he took with respect to this item. The fact that reserves owned during the test year did not produce revenues is not sufficient ground to exclude them from the rate base, for reserves are often obtained and properly held for future needs because of conditions beyond the control of the producer.

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[Mimeo., p. 37]

Furthermore, the record shows that additions to Phillips' Gas Department properties in the year 1955 not only replaced the San Juan reserves dollar for dollar, but added some seven million dollars to the net investment over and above the depreciation and depletion that was recorded in that year. Therefore we can conclude that eliminating the San Juan reserves from the 1954 test year rate base would not make that rate base more representative of the future. Phillips is continually obtaining reserves, and at certain times it has disposed of reserves, so that the actual reserves at hand in the test year are appropriate for inclusion in the rate base.

Finally, the Michigan Commission contends that certain "general and service" assets should have been excluded from the rate base. These assets are referred to by the examiner as a hotel, a lodge, a hospital, patents and trademarks. While these items as applicable to the entire com-

pany amount to $2,31,539, the adjustment as proposed by the staff would reduce the rate base by only $324,055. The staff had employed a short-cut method of adjustment as did Phillips by a somewhat different means. The examiner did not make an adjustment for these items on the ground that whether the allocation was made by Phillips' method or the staff method, a proper computation would be too complicated for a *de minimis* item. He said that to arrive at a correct result, it would be necessary to make a precise calculation of the total net investment in every general and service assets item which could be regarded as proper investment in order to determine whether the short-cut method fully reflected the entire amounts properly chargeable for each of such legitimate items. We agree with the examiner that under the circumstances no adjustment is appropriate for this item.

The matter of working capital was not a subject of controversy in the exceptions. However, since we recompute the amount employed by the examiner some explanation is desirable. The examiner accepted Phillips' claim in the amount of $29,841,420[32] and none of the other parties took specific exception thereto although Wisconsin's witness had stated that the amount was supported by insufficient evidence. The record, in fact, is deficient in support of Phillips' claim. The company's exhibit does set forth its amount for working capital divided into various categories[33] but does not show the method by which those amounts were reached.

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[32] The examiner actually shows $8,028,654 for the jurisdictional portion of the working capital.

[33]

Production facilities, dry gas leases	$ 6,281,978
Gathering facilities	3,209,581
Residue facilities	129,826
Oil production facilities, 100 percent oil leases	4,445,736
Oil and gas and cycling production facilities, joint product leases	15,774,299
	$29,841,420

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[Mimeo., p. 38]

As set forth in Appendix 3, we compute an allowance for working capital in the amount of $19,929,483. This amount is developed from evidence in the record using the methods that we have employed in previous cases dealing with electric companies and pipeline companies, and we see no reason why the same method may not be applied for the independent producers. Upon the basis of total direct, indirect and exploration expenses as allowed by us in this proceeding, less certain non-cash items, such as taxes and depreciation, we reach an amount for cash requirements, equivalent to operating expenses. One eighth of this, or 45 days' expenses we allow in the working capital. We then add the allowance for materials and supplies and prepayments to arrive at a total of $19,929,483.

Upon the basis of the considerations expressed above and including the allowance for working capital, we find that the proper rate base for Phillips including the Natural Gas Department, the Oil and Gas Department, exploration and development, gathering system and gasoline facilities and residue system, amounts to $424,775,939 as shown in Appendix 2.

32681

[Mimeo., p. 39]

RATE OF RETURN

The question of rate of return has been a matter of controversy in this proceeding as in many others, but there are involved here a number of considerations that we have not had to face in pipeline proceedings. The staff recommended a rate of return of 9 percent for Phillips, employing a method that utilized the earnings price ratio of Phillips equity securities and those of other companies. The examiner, in general, followed this method, but made a modification in the computation of the debt ratio and reached a

rate of return of 9¼ percent. Phillips opposed the earnings-price ratio method, but modified this method and used it in conjunction with a method based on data published by the Internal Revenue Service and a method based on a comparison of Phillips' earnings on investment with the earnings on investment of producing companies of an allegedly corresponding risk. Using these methods, Phillips contended for a rate of return of approximately 12 percent, in addition to the benefits of the tax incentives discussed below or a rate of return of 17 to 18 percent if the retention of the tax benefits were denied.

In order to reach a fair rate of return for Phillips, we will not employ any formula rigidly. This is a matter which "depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard for all relevant facts." *Bluefield Water Works and Improvement Co.* v. *P.S.C.*, 262 U.S. 679, 692-693. The goal of our inquiry is stated in *F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591, 603, where it is said that there must "be enough revenue not only for operating expenses but also for the capital costs of the business" including "service on the debt and dividends on the stock." Te return to the equity owner must be "commensurate with returns on investment in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital." This is another situation where we must apply our judgment to a multitude of interrelated facts which cannot all be weighed mathematically, but nevertheless we must reach a decision and in doing so shall take such factors into consideration which appear to us relevant.[34]

Before discussing the specific question of what rate of return is fair and reasonable for Phillips we should consider the effect of certain tax

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[34] See p. 13, citing *S.E.C.* v. *Chenery Corp.*, 332 U.S. 194 and other cases.

incentives arising from the internal revenue code. Under the present tax law, provision is made for certain additional deductions which have the effect of lowering Federal income taxes payable. The question has arisen whether the benefit of those tax provisions should belong to Phillips, the taxpayer, or its customers and the consumers. That is, whether Phillips' cost of service should be computed without utilizing these tax deductions while at the same time taking advantage of them on its tax return. The examiner used actual taxes payable in his computation of cost of service. Phillips and certain of the interveners argued that the benefits should be retained by it.

The additional tax deductions in this proceeding relate to percentage depletion under Section 613 and intangible drilling and development costs under Section 263(c). These provisions have been discussed in previous decisions by us,[35] and it will only be necessary here to cover them briefly.

The percentage depletion incentive arises from Section 613 of the Internal Revenue Code as an alternate to the "reasonable allowance" standard of Section 611, which in practice means depletion on a cost basis. Under Section 613, the allowance for depletion on oil and gas wells is the lesser of either 27½ percent of the "gross income" or 50 percent of net income. An option to deduct as expense the intangible drilling and development costs under prescribed regulations is continued by Section 263(c) of the Internal Revenue Code of 1954. Proposed regulations provide that the owner of an operating mineral interest in oil or gas wells may at his option deduct, that is, "expense" intangibles, including amounts spent for labor, fuel, repairs, hauling and supplies in drilling wells, clearing ground and construc-

[35] *El Paso Natural Gas Co.*, 22 FPC 260, 265-269, reversed as *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567 (5th Cir. 1960); *United Fuel Gas Co.*, 22 FPC 127, 512.

tion. In other words, instead of capitalizing the intangibles and depleting them over the life of the well, the producer may deduct them in the year incurred. See proposed Regulation § 1.612-4(a), (d), 603 C.C.H. 3552 and the corresponding regulations under the 1939 Code, Regulation 11 § 39.23 (m)-16(a) (d). In our *El Paso* and *United Fuel* decisions, we concluded that when the percentage depletion and intangibles provisions are considered together in relation to the taxpayer's property as a whole, they result in a tax saving rather than a tax deferral. This is because the percentage depletion deduction depends upon revenues, so that there

is no decrease in deductions for depletion during the life of a gas lease because of expensing the intangibles in the first year. We further concluded in those two proceedings that it was the intention of Congress that the taxpayers should receive the benefit of these provisions. However, since the result was that the taxpayer would receive revenues without a corresponding expense, we said that the tax savings should be considered in determining a fair rate of return.

In the present proceeding for the test year 1954, Phillips had a deduction for depletion in accordance with the tax statute that exceeded the book depletion by the amount of $36,916,206, and a deduction for intangibles expensed in accordance with the tax statute that exceeded the amortization per books in the amount of $7,868,517. Thus a total additional deduction results because of the two statutory tax incentives in the amount of $44,784,723 and a tax saving of $23,288,056, at the tax rate of 52 percent.

By opinion dated August 2, 1960[36] the Court of Appeals for the Fifth Circuit remanded the *El Paso* proceedings.

[36] *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567 (5th Cir. 1960).

The Court concluded that there was no statutory authority for the Commission to treat actual savings in taxes any differently than any other savings, that must be passed on to the consuming public. Therefore no amount representing tax benefits or tax savings could be included in the cost of service. The Court said, however, that "full effect must be given to the Congressional intent to make the several tax savings available to the taxpayer" but not in the form of "additional profits." The savings were available, the Court said, to make it so much easier for the natural gas producers in competition with other fuels and other industries to earn a fair return.

In the present proceeding the tax saving of $23,288,056 amounts only to 6.63 percent on Phillips' well mouth properties. As will be seen, a fair return for Phillips would be at a higher rate than this under the contentions of any of the parties, but whether Phillips receives return as a tax incentive or as a specific allowance, does not affect the result. It must have a fair return on its well mouth, and all of its jurisdictional properties in any case. Therefore, we do not set forth the tax incentives as a specific item in the cost of service, for we are allowing a larger return than permitted by the tax incentives. We may now turn to a consideration of the factors relating to a fair rate of return apart from the tax incentives.

Phillips, as already noted, is a large company with assets of over a billion dollars, whose gas business is only a small fraction of the whole. Such a company is in a very strong position to raise capital. As a company with a continuing program of exploration and production it differs from other companies whose activities are sporadic or are merely holding reserves.

32684

[Mimeo., p. 42]

Phillips argues that it is a fallacy to apply to gas production operations a rate of return based upon the over-all

cost of its capital because of the peculiarly risky nature of the oil and gas production business. It says that the cost of capital for the enterprise as a whole is less than the cost of capital for these risky operations. However, the financing of Phillips and its capital costs are affected by the nature and success of the whole business, and it would be impossible on this record to determine the cost of capital for part of its business. Furthermore, the evidence indicates that the companies that are solely producers have a higher market demand for their equity securities in relation to earnings than the companies with integrated operations. This is possibly because investors sought a hedge against inflation and invested in these stocks in order to acquire a share in raw materials in the ground. In any case, investors, according to the record, appear willing to accept a lower return from purely producing companies than from the integrated companies. Of course, as the examiner points out, the risk inherent in Phillips' producing operations is less than that for the producing operations of the large number of smaller companies. Nevertheless, production of gas creates risk in spite of the willingness of investors to purchase the securities of producers, and this risk must be taken into consideration in arriving at a fair rate of return. We should not base our findings wholly upon a passing tendency of investors.

The presentation by both Phillips and the staff are on the basis of Phillips' capitalization of December 31, 1955. In spite of the exceptions of the Southern California Companies, the capitalization on that date was more representative of the future than in 1954, for an issue of bonds was converted in 1955. Just as we made an adjustment for the related interest deduction for income tax purposes, we shall likewise adjust the capitalization ratio.

(32684)

At the end of 1955 the company's actual debt ratio was 11.6 percent and the cost of it outstanding debt was 3.2 percent as shown by its capitalization:

Long-term Debt	*Amount*		*Cost to Company*
2¾% Debentures, 1964	$28,050,000		2.82%
Subsidiaries' Loans ¾% due 1963	81,000,000		3.36
Subsidiaries' Funded debt	9,120,000		3.00
Purchase obligation	775,583		3.00
Total long-term debt	$118,945,583	11.6%	3.20%
Common Equity			
Common Stock	$455,838,132		
Earned Surplus	443,872,017		
Capital Surplus	1,431,827		
Total Common Equity	$901,141,976	88.4%	

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[Mimeo., p. 43]

There was no dispute about these figures, but the staff contended that Phillips' actual debt ratio and actual cost of debt should be adjusted to reflect as an interest-free loan an item of deferred Federal income tax liability in the amount of $19,162,355, arising from the accelerated amortization provisions of Section 168 of the Internal Revenue Code. This would decrease Phillips' cost of debt to 2.76 percent. The examiner refused to make this adjustment, and we agree. The accelerated amortization provisions were to benefit the taxpayer, not the consumers. They represent an advantage bestowed by Congress to encourage the construction of emergency facilities, and we are not authorized to take away this advantage. *City of Detroit* v. *F.P.C.*, 230 F. 2d 810, 822 (CADC), *certiorari denied*, 352 U.S. 829.

We cannot agree to the exception made by the Michigan Public Service Commission on this point.

In past proceedings dealing with the rates of both electric utilities and natural gas pipeline companies, we have always considered a number of factors in arriving at a proper allowance for common equity and finally a rate of return. In doing so, we have paid considerable attention to the earnings-price ratio of the company involved and other companies similarly situated.[37] The advantage of the earnings-price ratio as a critique is that it shows what investors will pay for the securities of the company involved in relation to contemporary earnings. But earnings-price ratios have pronounced drawbacks in some proceedings, including this one. Investors are interested in contemporary earnings, but they may be interested in other things as well, such as future earnings, possible discovery of large reserves, tax advantages, a hedge against inflation, so that the market price may reflect factors other than earnings. This is apparently true here, for the record shows that while the earnings on the book value of independent producers' equity have declined somewhat from 1949 through 1955, market prices of their stock have risen substantially. Furthermore, it is plain that potential investors in Phillips are not greatly influenced by Phillips' position in the gas business, since but six percent of its gross income comes from this source. While as we said in the *Southern Natural* case[38] the study of earnings-price ratios over a period of years may properly be used with judgment, together with other factors, in determining a reasonable allowance for equity, this is not a case

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[37] *Pennsylvania Water & Power Co.*, 8 FPC 1, 79-80, affirmed *Pennsylvania Water & Power Co.* v. *F.P.C.*, 193 F. 2d 230 (CADC), affirmed 343 U.S. 414; *Michigan-Wisconsin Pipe Line Co.*, 13 FPC 326, Docket No. G-1678, July 30, 1954, mimeo p. 29; *El Paso Natural Gas Co.*, 13 FPC 421 (1954); *Southern Natural Gas Co.*, 24 FPC 26 (1960); *Tennessee Gas Transmission Co.*, 24 FPC 204 (1960).

[38] *Southern Natural Gas Co.*, 24 FPC 26 (1960).

where earnings-price ratios should be a controlling factor in arriving at a fair rate of return.

32686

[Mimeo., p. 44]

While Phillips employed the earnings-price ratio method with adjustments, as already noted it relied on two other methods. One is the earnings-book value approach. By this method there is computed the ratio of earnings to book value of the common equity of comparable companies rather than the ratio of earnings to market price. The earnings-book value ratio is then applied to the equity capitalization. In employing this method, Phillips made use of a staff witness' list of companies, designated *Class A*, which are engaged solely in producing operations. In the seven year period, 1949-1955, Phillips noted that the average earnings-book value ratio for these companies was approximately 19 percent. Assuming an average borrowed capitalization of 14 percent and an interest rate of 4 percent, the 19 percent return on equity capital would result in an average rate of return for the Class A companies of approximately 17 percent, which Phillips contended would be about a reasonable allowance including tax incentives.

Although actual earnings related to book value cannot be decisive in determining a fair return, they constitute an important factor to be considered as showing what comparable companies are earning on the book value of their assets and the relation of Phillips' earnings to their earnings. This approach as employed by Phillips, however, mistakenly relies on the Class A producer companies whose operations differ from Phillips' integrated operations. The examiner notes that the earnings-book value ratios for the Class C integrated companies for the seven-year period used by Phillips amounted to only 15.3 percent, while if the five-year 1951-1955 period had been used, a ratio of only 14.8 percent would be obtained. If a group of 40 companies including both producers and integrated companies is examined, we find that the earnings over the five-year period is approxi-

mately 17 percent on their book value. Phillips' own earnings-book value ratio for the seven-year, 1949-1955 period was 12.1 percent and for the five-year, 1951-1955 period was 12.3 percent.

The other method proposed by Phillips as an alternative to the earnings-price ratio method was based upon Internal Revenue Service data. As stated by the examiner, Phillips' witness used statistical data, published by the Internal Revenue Service, showing balance sheet items and profit and loss statements. Using this data, Phillips' witness computed for the category of crude petroleum and natural gas production, a composite return to equity capital of 11.8 percent for the 1947-1953, seven-year period. Adding an estimated cost of financing of .75 percent, he arrived at a cost rate on common equity of 12.55 percent. This figure, combined with a 3.20 percent rate on debt, produced an overall rate of return of 11.46 percent. Adjusting to compensate for the risk of the "losers", the witness rounded out the rate of return to 12 percent. This method is based on data for companies which are very largely producers only and is subject to the further defect that it reflects only those companies reporting taxable income computed in a somewhat different way than would be net income for rate making purposes.

32687

[Mimeo., p. 45]

We may now consider the earnings-price ratio method as employed by the staff and as modified by Phillips. The staff witness determined an earnings-price ratio of 8.5 percent based on an average for the five-year period, 1951-1955. For this purpose he used a group of 41 companies, including as Class A, those companies which were strictly producers of oil and gas, as Class B, those companies which were producers of oil and gas and were also engaged in refining, and as Class C, the integrated companies producing, refining and marketing. To the ratio of 8.5 percent he added an allowance for the cost of financing of .75 percent and an

investment factor of .75 percent over the "bare bones" cost of equity in order to enable the company to attract capital at reasonable cost, thus reaching a total allowance of 10 percent on Phillips' common equity.

In employing the earnings-price ratio technique, Phillips used the 20-company Class C group and the nine-year period, 1947-1955 to arrive at an earnings-price ratio of 12.9 percent. We agree with the examiner that the appropriate period was the five years, 1951 to 1955, because that reflects the more recent trend of earnings-price ratios. On the question whether to use the 20-company Class C group or the 41-company group, we are in agreement with the staff and the examiner that if the earnings-price ratio method is to be used, the 8.5 percent ratio applicable to the larger group should be employed. While Phillips itself is an integrated company, producing, refining and marketing, the record indicates that the companies in the Class C group are not strictly comparable to Phillips and, furthermore, we are regulating not all of the integrated operations but only the results of producing operations so that some additional weight should be given to such operations. On the other hand, we do not believe it would be appropriate to use the Class A producer group solely, for the financing of the producing operations presumably is affected by the fact that production is combined with refining and marketing. It is of some significance that the earnings-price ratios of the 41-company group for each year from 1947 to 1955 are very close to the earnings-price ratios of Phillips for those years and that the 5-year average for the 41-company group is 8.5 percent while the 5-year average for Phillips is the very close amount of 8.8 percent.

There appears to be no dispute about the staff witness' allowance of .75 percent for financing and this should be added to the earnings-price ratio. More difficulty is created by the allowance of an additional .75 percent over the "bare bones" equity cost. The staff witness testified that the market value of Phillips' common stock should be some-

where in the range from 1.12 or 1.15 times book value, to perhaps, around 1.40 or 1.50 times book value. He was of the opinion that 1.40 times book value would permit the company to maintain its financial integrity and to attract capital on reasonable terms and that if Phillips were given a rate of return somewhere around 9 percent, involving an allowance .75 percent for equity financing and .75 percent as an adjustment over "bare bones" equity cost, the market price would be around 1.40 percent of book value, all other factors being equal. There is no mathematical way to make such an allowance, but some allowance should be made above the "bare bones" cost of equity, and we think that the .75 percent used by the staff witness would be a correct adjustment to make. Phillips multiplied its unadjusted earnings-price ratio of 12.9

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[Mimeo., p. 46]

percent plus the .75 percent financing factor by the 1.40 market factor to arrive at an adjusted cost of common equity of 19 percent, which in turn resulted in an overall rate of return of 17 percent. This method is not only a mechanical method of solving a problem which is a matter for judgment, but arrives at a result which is not required by the demand of the market for Phillips' stock. The two .75 percent adjustments to the earnings-price ratio of 8.5 percent would bring the allowance for common equity up to 10 percent.

In our opinion the various statistical methods do not provide a complete basis for determining a rate of return for an independent producer of gas. It is clear that the risks of this business are greater than those of an electric utility or natural gas pipeline. While we cannot rigidly compare these companies with Phillips, for the circumstances and times are different, we do think that an allowance for common equity for a producer should be comparable to or greater than that for a pipeline company or an electric company. Some of these pipeline and electric cases are as follows:

Name	Citation	Date	Common Equity	Overall Return	Equity Capitalization Ratio
Pennsylvania Water & Power Co.	8 FPC 1	1- 4-49	8.64	5.25	35.71
South Carolina Generating Co. (based on parent South Carolina Electric & Gas Co.)	16 FPC 52	10-24-56	10.5	5.55	27.8
Michigan-Wisconsin Pipeline Co. G-1678	13 FPC 326	7-30-54	10.3	6.00 (pro forma)	31.5
El Paso Natural Gas Co. G-4769	13 FPC 421	11-26-54	14.4	6.00	19.0
Colorado Interstate Gas Co.	19 FPC 1012	6-21-58	12.85	6.00	22.6
Southern Natural Gas Co. Gas Co. G-20509	24 FPC 26	7- 8-60 (pipeline only)	10.18	6.5 (pro forma)	35.8
Tennessee Gas Transmission Co. G-19983	24 FPC 204	8- 9-60 (provisional)	10.12	6⅛	29.5

One plain difference between Phillips and the companies listed here is that Phillips' capitalization consists of 88.4 percent equity and only 11.6 percent debt. This, of course, reduces the risk found in companies of thinner equity. While we believe that Phillips should be granted an allowance for common equity in excess of 10 percent our allowance will be limited by Phillips' high equity capitalization. By this we are not reversing the policy announced in previous cases of encouraging companies to improve their capitalization ratios, for in those cases we were generally dealing with much lower equity ratios as evidenced by the *Michigan-Wisconsin* and *El Paso* cases above.

At the hearing, and in its briefs, Phillips made an extensive presentation designed to show increasing demands for gas by consumers and the producers' increasing problem of supply. As stated by the examiner, the presentation attempted to show the rapidly increasing demand for natural gas, and the failure of discoveries to keep pace with the demand, the increasing depths of drilling resulting in increasing drilling costs, the rising exploration expenditures, the decreasing discoveries per foot of hole drilled, the declining ratio of net earnings to net investment in total gas and oil production and the increasing gas and oil ratios making the producer more dependent than formerly upon income from gas. As stated by the examiner, this evidence appears to relate to rate of return as well as the question of the percentage of exploration costs which should be allocated to gas.

It is clear enough that the national demand for gas is increasing. Phillips' witness estimated that the national demand would increase from 10 trillion cubic foot in 1955 to 15 trillion cubic foot in 1965. It is clear enough that the industry must continue to find additional reserves of gas

and this must come from wells that are drilled ever deeper into the earth and some of them off shore in the Gulf of Mexico. Of course, these deeper wells must be drilled at an increasing cost per foot of depth. It is also true, as Phillips contends, that oil and gas producers must have funds available as their present wells are depleted to drill new wells and find new reserves. Since these new wells will cost a great deal more than the old ones, the oil and gas producers are being faced with the constant necessity of plowing back into their business a substantial part of their revenue above depreciation and depletion accruals.

In view of these practical problems in the gas industry some allowance must be made in the rate of return to promote the continued exploration for and production of gas. The allowance of such an incentive is contemplated by the recent *El Paso* case[39] and the *City of Detroit* case.[40] The amount cannot be determined by any formula, and we can conceive of no evidence that would enable us to reach an amount other than by the exercise of our judgment with all the circumstances in mind.

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[Mimeo., p. 48]

Upon the basis of all the factors discussed above it becomes necessary to determine an allowance for common equity for Phillips. We have noted the comparatively high earnings on equity of the integrated companies and the even higher earnings of the producers, offset by the fact that Phillips' own unregulated earnings on equity have been just a little over 12 percent. Phillips' Internal Revenue data with its disadvantages resulted in a cost rate on common equity of 12.55 percent. The earnings-price ratio method as employed by the staff and the examiner would result in an allowance of 10 percent. But it is clear that

[39] *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567 (5th Cir. 1960).

[40] *City of Detroit* v. *F.P.C.*, *supra*.

something more is needed if that method is employed in view of the allowances we have employed in pipeline cases and the need to encourage continued exploration for and production of gas. As against these factors tending to increase the return, we also bear in mind that Phillips is a large company and well established in the conduct of its gas business, its oil business and its other extensive operations. In these circumstances we think that an allowance for common equity of approximately 12 percent would be fair and reasonable.

Taking the cost of debt capital of 3.20 percent and the allowance for common equity of 12 percent, we compute a fair rate of return as follows:

Allowance		*Capitalization*	
Debt	3.2	11.6	.37
Common Equity	12.0	88.4	10.61
			10.98 percent

The overall rate of return of 10.98 should be rounded off to 11 percent. As such we believe that it takes into account all factors necessary for determining a fair return and includes all that is required from the constitutional or the regulatory point of view.

As noted previously tax incentives will not be included in the cost of service. It appears from the data of record that the sum of the additional tax deductions for statutory depletion, intangible well drilling costs and interest expense would amount to $46,680,450. This is approximately $44,900 less than the return allowed of $46,725,353 (See Appendix 2). Accordingly, we shall add an amount rounded to $45,000 to the cost of service to provide an allowance for Federal income tax taking into consideration in this tax allowance the effect of a very small credit to working capital. Because

of its small amount we do not show this credit as an actual deduction from working capital.

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[Mimeo., p. 49]

COST OF SERVICE

On the basis of the foregoing discussion in connection with the decision of the examiner, we determine Phillips' cost of service for its jurisdictional gas operations in the amount of $55,548,054 or 11.309 cents per Mcf, as set forth in Appendix 10, subject to adjustment for Phillips' purchased gas costs, royalties, and gathering taxes.[41]

The appendix shows the allocation of the cost of Phillips' own produced gas, in the amount of $37,924,378, between non-jurisdictional field sales, jurisdictional field sales, and costs as delivered to gathering systems on the basis of volume. In the gathering category are included the $28,180,164 portion of Phillips' produced gas costs, purchased gas costs in the amount of $30,320,225, and gathering system and compressing costs in the amount of $18,452,321. These costs are distributed between raw gas sales, liquids extracted, and residue sales on the basis of Btu's as previously discussed. The costs allocated to residue sales plus residue system costs and costs allocated to raw gas sales are then

[41] The examiner allowed increased royalties and gathering taxes in Phillips' cost of service as computed by him to reflect increased revenues resulting from his determinations. There is no question that such an adjustment is proper. If the cost of service determined by us were translated into revenues, we estimate that Phillips' royalties and gathering taxes would be increased by approximately $1,500,000. Likewise, we estimate that Phillips' purchased gas costs as a result of the operation of the percentage-type casinghead contracts of its suppliers on an overall basis would be increased by approximately $3,700,000. There is no purpose in making an exact computation here because the cost of service computed by us exceeds Phillips' revenues, and we are terminating all proceedings (with two irrelevant exceptions). However, if the computation were made on the basis of revenues reflecting our cost of service, our adjusted cost of service would exceed that computed by the examiner.

allocated between non-jurisdictional sales and jurisdictional sales. To the jurisdictional costs are added cost distributed to the jurisdictional field sales and regulatory commission expense to arrive at the total cost of jurisdictional service of $55,548,054 or 11.309 cents per Mcf, subject to redetermination for purchased gas costs, gathering taxes and royalties.

32692

[Mimeo., p. 50]

RATES

Having determined Phillips' cost of service, the next step would ordinarily be to alter Phillips' rates to reflect this cost of service. We are authorized in an investigation under Section 5(a) to determine rates prospectively and, of course, we can determine rates for the past periods with respect to the rate schedules involved in the Section 4(e) proceedings consolidated with this investigation. However, a very serious problem is before us.

We may first note the greatly varying contentions of the parties. In these proceedings Phillips contended for a uniform rate applicable to sales to all of its customers[42] subject to adjustment for point of delivery, pressure, dehydration and amount of sulphur (whether sweet or sour). The examiner used the company-wide method, but in their exceptions a number of the interveners objected vigorously and advocated variously other solutions, such as basing the rates on the existing contract rates or field prices. The staff advocated an area method of setting rates. On oral argument Phillips stated that it was not wedded to any particular system of rates as long as it recovered its total cost of service, and the State of Wisconsin and the California Commission which had objected to company-wide

[42] Except with respect to percentage-type casinghead contracts.

rates, admitted the record was insufficient to support other methods and withdrew their objections.

As already indicated, Phillips' operations are conducted in widely separated areas, and it produces gas of varying qualities and serves diverse customers under different conditions. Physically, Phillips owns gathering systems and holds leases in Kansas, in central Oklahoma, in the Panhandle of Oklahoma and Texas, in eastern New Mexico and western Texas along the Gulf Coast of Texas, in eastern Texas and other scattered localities. Its jurisdictional sales are represented by hundreds of rate schedules on file with this Commission.

The present proceeding involves an investigation of Phillips' rates on the basis of a record including evidence on the alternate test years 1954 and 1956 of which we chose 1954 in accordance with the decision of the examiner. From our knowledge of the industry, it is clear enough that costs and prices of gas in the field have greatly increased since that time. For instance, we have suspended approximately 95 rate changes filed by Phillips subsequent to the hearing in these proceedings. Some of its more recent filings involve substantial increases.[43] Therefore we do not deem it appropriate to prescribe

or require that Phillips file rates for the future based upon the present record. In fact, if this order provided for rates

[43] For example see the following increases:

Buyer	Docket No.	Amount Suspended	Effective Subject to Refund
Michigan-Wisconsin P. L. Co.	G-19032	$1,610,504	1- 1-60
Panhandle Eastern P. L. Co.	G-19845	2,717,526	3-26-60
El Paso Nat. Gas Co.	G-18417	2,212,264	1- 1-60
El Paso Nat. Gas Co.	G-20404	1,090,103	6- 2-60
El Paso Nat. Gas Co.	G-20403	3,385,616	6- 1-60

for the future effective in 1960 but based on the test year 1954, it might easily occur that the rates approved here would be lower than those approved in some of Phillips' suspension proceedings now before us. The consequence of this would be that Phillips would be required to decrease its rates in 1960 based upon an earlier test year, a result without reason or justice.

As a result we shall terminate the rate investigation proceedings in Docket No. G-1148 under Section 5(a). Phillips' customers will not be substantially injured, for Phillips' rate filings have been subject to our continuing surveillance and many large increases filed by it have been suspended under Section 4(e) of the Act and are currently the subject of proceedings before us. Furthermore, there is nothing to show that Phillips' contracts relating to Phillips' diverse conditions of sale are unduly discriminatory or preferential. Additionally its customers and consumers will receive the protection of our area pricing standards announced at this time. Phillips will not be injured, for we are thus leaving in effect its contract structure; it has had the privilege of filing increased rates and has done so in substantial amounts as already noted.

Our approach must be similar with respect to the twelve Section 4(e) proceedings consolidated herewith. Except in one minor case[44] all of these proceedings involve rates which have become effective after the test year, but have been superseded by other rates suspended by us in other proceedings. They must be considered in the light of the record in this case which is based on the cost of service method of regulation, but our conclusions here should not bind future determinations of Phillips' rates either in Section 4(e) proceedings or rate investigations under Section 5(a). The record in this proceeding indicates that these rates

[44] Phillips' Rate Schedule No. 68 for service to Cities Service Gas Co. involving an increase of $21,324, suspended by us in Docket No. G-8623 until May 1, 1955 is still in effect.

have produced revenues less than Phillips' cost of service during the periods that they were in effect. The cost of service determined by us of $55,548,054 or 11.309 cents per Mcf is substantially in excess of Phillips' applicable jurisdictional revenues of $45,568,291.

Although there is considerable diversity among the rates, there is nothing in the record to show that these past rates reflecting the different conditions of sale are unduly discriminatory or preferential. To allocate costs to each of them would require reopening the proceedings and the introduction of elaborate evidence. Little would be accomplished by way of adjusting them in any case since neither Phillips nor this Commission have authority under the Act to increase any of them retroactively above the filed level. On our part we would like to disturb area rate patterns as little as possible, particularly on a retroactive basis, having in mind the involved business arrangements that have arisen between the producers and their customers as the industry has developed. We thus find no purpose in continuing the Section 4(e) proceedings and will order that they be terminated with two exceptions discussed below.

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[Mimeo., p. 52]

Our disposition made here avoids the necessity of dealing with the many questions raised in this proceeding as to Phillips' rates, but one question remains, and that is whether with respect to certain contracts Phillips was authorized to file increased rates. Under the *Mobile* case,[45] of course, a seller of gas may not file an increased rate unless contractually authorized. Phillips filed increased rates for service to El Paso, in Docket No. G-11217, to Michigan-Wisconsin in Docket No. G-10793, and to Panhandle in Docket No. G-10883 on the basis that the spiral clauses in its contracts authorized such increases. The examiner found

[45] *United Gas Company* v. *Mobile Gas Corporation*, 350 U.S. 332.

that these clauses in Phillips' contracts with the three companies provided customer consent to increased rates above what would have otherwise been the contract level.

The spiral clauses provide that when the commodity index shall have increased more than a prescribed number of points and a general increase in the customer's rates shall have been put into effect, then Phillips' rates to the customer shall be increased in proportion. Certain of the California interveners contend in their exceptions that the spiral clauses are against the public interest and void, so that they cannot be used as a basis for consent to rate increases. While we do not approve of such clauses in principle, there is not sufficient basis on this record to hold them so derogatory of the public interest as to be void as a matter of law. Therefore, the spiral clauses in this proceeding provide a contractual consent to rate escalations. It may be recalled that the Supreme Court found no invalidity where the contract provided that the buyer should pay the rate the seller had on file with the Commission. *United Gas Co.* v. *Memphis Gas Div.*, 358 U.S. 103. This contract with an unlimited right to file increased rates was not held void; neither have contracts with spiral escalation clauses in them been called void. *Phillips Petroleum Co.* v. *F.P.C.*, 227 F. 2d 470 (CA 10), *certiorari* denied, 350 U.S. 1005; *Kerr-McGee Oil Industries, Inc.* v. *F.P.C.*, 260 F. 2d 602 (CA 10). We emphasize, however, with the examiner that Phillips' costs have been determined in this proceeding independently of any spiral clauses. We need not require that they be eliminated, since Phillips has already agreed to do so.

El Paso argues that the spiral escalation clauses in its contracts with Phillips have not been activated and therefore do not form a basis for Phillips' rate increase filing in Docket No. G-11217, made as a result of El Paso's rate increase filing in Docket No. G-4769. El Paso contends in

its exceptions, dated July 27, 1959, that the contracts clearly provide that Phillips would not be entitled to increased rates until by final decision El Paso's increased rates are finally determined. However, the contracts provide that the price for gas shall be adjusted "when revised rates shall become effective." El Paso's rates in Docket No. G-4769 were allowed to go into effect subject to refund on April 15, 1955, and we agree with the examiner that this provided customer consent to Phillips' rate filing in Docket No. G-11217. We also agree with him that the spiral clauses must be

[Mimeo. p. 53]

given only tentative effect because the rate filing when it became effective was subject to Commission action and court review.[46] Thus, if the amount of the Phillips' escalation increase under the spiral clause as established when El Paso's rates are finally determined, should be less than the amount of Phillips' proposed increase in Docket No. G-11217, the excess portion would be a unilateral increase barred by the *Mobile* doctrine and would have to be refunded.

These same conclusions are also applicable to the similar spiral escalation clauses in the Phillips-Michigan-Wisconsin contracts which are the subject of Docket No. G-10793 and the Phillips-Panhandle contracts which are the subject of Docket No. G-10883. Michigan-Wisconsin made no contention that the escalation clauses were not operative, but Panhandle contends that any increase granted Phillips in Docket No. C-10883 should be conditioned on the effect of a final order in Panhandle's rate proceeding in Docket No. G-2506.

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[46] In Docket No. G-4769, the Commission issued its order determining El Paso's rates on August 10, 1959, 22 FPC 260, remanded by the Court. *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 537 (5th Cir. 1960).

Therefore we shall leave pending Docket Nos. G-11217 and G-10883 until a final decision is made either by us or competent court in Docket Nos. G-4769 and G-2506, respectively. At that time Phillips may move that Docket Nos. G-11217 and G-10883 be terminated, and any necessary refunds may be ordered if the rates approved for El Paso in Docket No. G-4769 and for Panhandle in Docket No. G-2506 are not sufficient to permit Phillips under its contracts to file the increased rates involved in Docket Nos. G-11217 and G-10883. Of course, no other matter with respect to these two dockets will remain open.

Our dispositions here leave outstanding almost a hundred other suspension proceedings relating to Phillips' rates. We do not wish to prejudge those proceedings, but it would appear that on the basis of the present record that Phillips' costs probably exceed its revenues at least up through the year 1958, after which very substantial further rate increases were filed by Phillips. Therefore it may be reasonable to terminate a great many of these suspension proceedings, and we invite the filing of motions to this effect on the theory that little or nothing would be accomplished if hearings were held and a determination of Phillips' costs in each case were made. All parties to those proceedings would, of course, have opportunity to object to such motions. We believe this would be a reasonable step to take and it would have the effect of limiting proceedings dealing with Phillips' rates to the year 1959 and later.

32696

[Mimeo., p. 54]

THE SETTLEMENT PROPOSAL

On April 8, 1960, Phillips filed a proposal to settle the present consolidated proceedings. The gist of its proposal is that the Commission would accept all of its contract rates involved and would terminate the various proceedings without refund. It contends that the prompt settlement of these

extended proceedings without court review, otherwise almost certain, would be of great benefit to the Commission, its staff and all segments of the natural gas industry. It adds that the amounts collected by Phillips, subject to refund, are substantial, are increasing each month and may adversely affect Phillips' exploratory program. Phillips notes that under its settlement proposal the annual revenue to Phillips at April 1, 1960, contract prices, from the contracts which were the subject of the present hearing, amounts to $70.8 million, compared to Phillips' claimed cost of service of $92.3 million.

While it is possible that Phillips' proposal may not be unreasonable as a settlement, it was rejected by a number of parties to this proceeding including Southern California Companies, the State of Wisconsin and Public Service Commission of Wisconsin, Minneapolis Gas Company, the Eastern Companies, the Michigan Public Service Commission, and P.G.&E. The grounds given, stated variously, are that the settlement would give Phillips its entire filed rate increase, would be contrary to the findings of the examiner, would be an abdication of regulation, and would fail to settle questions of importance to the industry.

Because of these rejections the settlement proposal may not now be accepted as a settlement. It does not represent a new solution to the issues presented by this proceeding, but rather, acceptance of Phillips' present and past contract prices, many of which are now the subject of other proceedings. We therefore have no basis on which to accept it without agreement of the parties. However, if Phillips desires to renew its proposal or a similiar proposal, it is free to do so, in the light of this opinion and the area pricing standards.

The Commission further finds:

(1) Phillips Petroleum Company is a natural-gas company subject to the provisions of the Natural Gas Act as determined by the Supreme Court of the United States in *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, and the sales of natural gas for resale which are the subject of this order, are sales of natural gas in interstate commerce and are subject to the jurisdiction of the Commission.

(2) The total jurisdictional cost of service determined for Phillips in this proceeding is $55,548,054, or an average of 11.309 cents per Mcf as set forth in the appendices attached hereto subject to adjustment of purchased gas costs, gathering taxes and royalties.

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[Mimeo., p. 55]

(3) It is necessary and appropriate in the administration of the Natural Gas Act and good cause exists that the proceeding under Section 5(a) of the Natural Gas Act in Docket No. G-1148 and the proceedings in Docket Nos. G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10359, G-10793, and G-11125, under Section 4(e) of the Act be terminated and Phillips' obligation to refund excess charges with respect to those dockets be discharged.

(4) It is necessary and appropriate in the administration of the Natural Gas Act that proceedings in Docket Nos. G-10883 and G-11217 remain open pending completion of proceedings in Docket Nos. G-4769 and G-2506 as provided below.

The Commission orders:

(A) The proceedings in Docket Nos. G-1148, G-3175, G-4333, G-6621, G-7773, G-8623, G-8695, G-8883, G-10359, G-10793 and G11125 are hereby terminated and Phillips'

obligation to refund excess charges with respect to those dockets is hereby discharged.

(B) Upon the issuance of a final Commission or Court decision in El Paso's pending Section 4(e) rate proceeding in Docket No. G-4769, Phillips shall file with the Commission a Motion Requesting Termination of its Section 4(e) proceeding in Docket No. G-11217. A determination will thereupon be made of the appropriate Phillips Section 4(e) rates in Docket No. G-11217, based upon the rate increase ultimately approved for El Paso in Docket No. G-4769, but in no event to exceed the rate filed in Docket No. G-11217. The Phillips Section 4(e) proceeding in Docket No. G-11217 will then be ordered terminated, subject to such appropriate refund order, if any, as may be warranted in the event that El Paso's proposed Section 4(e) rate increase in Docket No. G-4769 may not have been approved *in toto*.

(C) Upon the issuance of a final Commission or Court decision in Panhandle's pending Section 4(e) rate proceeding in Docket No. G-2506, Phillips shall file with the Commission a Motion Requesting Termination of its Section 4(e) proceeding in Docket No. G-10883. A determination will thereupon be made of the appropriate Phillips Section 4(e) rate in Docket No. G-10883, based upon the rate increase ultimately approved for Panhandle in Docket No. G-2506, but in no event to exceed the rate filed in Docket No. G-10883. The Phillips Section 4(e) proceeding in Docket No. G-10883 will then be ordered terminated, subject to such appropriate refund order, if any, as may be warranted in the event that Panhandle's proposed Section 4(e) rate increase in Docket No. G-2506 may not have been approved *in toto*.

(D) Exceptions not granted herein are hereby denied.

32698

[Mimeo., p. 56]

(E) The presiding examiner's decision is adopted as the decision of this Commission to the extent not inconsistent with this opinion and order.

(F) The motion of the Mid-Continent Oil & Gas Association to file a brief *amicus curiae* is hereby granted.

By the Commission. Commissioner Kline, concurring in part and dissenting in part, filed a separate statement.

32699

KLINE, Commissioner, *concurring* in part and *dissenting* in part:

I concur in the results reached in this case, namely, the dismissal of the Section 5 (a) proceeding instituted by the Commission against Phillips, and the disposition made by the Commission of the various Section 4 (e) rate increase cases. I do not concur in the cost of service determined for Phillips.

I also concur with the majority (1) that the traditional rate base cost-of-service method of fixing rates is generally neither an administratively practical or economically sound method to use to determine the rates of any individual independent producer, (2) that while ordinarily inappropriate, it can be used in this case to determine the justness and reasonableness of the rates charged by Phillips during the test year 1954 and the several years following as to which the 1954 test year can be considered representative, and (3) that we cannot in this proceeding fix Phillips' present or future rates.

I also concur in most of the methods of allocation and some of the rate-making principles adopted by the majority. I dissent vigorously to the method of allocation of explora-

tion costs proposed and adopted by the majority and to certain of the other rate-making principles and findings contained in the opinion. The adoption of the method of allocation of exploration costs and other rate-making principles which I advocate would not affect the outcome of this case, although it would result in a different cost of service.

There have been many differences between my colleagues and myself on the various issues of this case, on how we should regulate the rates of independent producers in the future, and the extent to which we should discuss these matters in this opinion and in the statement of policy issued this day. Although I deem it entirely too vague and inadequate, I have joined in the statement of policy solely because it represents action rather than inaction.

I shall not at this time set forth my views on these various issues for to do so would result in further delay in the issuance of this opinion. I shall express myself fully on these various matters when we pass upon the petitions for rehearing which will undoubtedly be filed in this proceeding, or at some other appropriate future time.

Arthur Kline, Commissioner

PHILLIPS PETROLEUM COMPANY

COST OF SERVICE
YEAR 1954

Description	Total	Natural Gas Department	Oil & Gas Production Department					
			Total	100% Oil Leases	Joint Products Including Cycling	Exploration and Development	Gathering System & Gasoline Facilities	Residue System
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
DIRECT EXPENSE								
Operating Expense	$ 25,872,563	$ 457,300	$18,281,379	$ 7,811,373	$10,470,006	$ —	$ 6,521,463	$ 612,421
Other Lease Expense	980,725	119,024	831,296	175,601	655,695	—	28,153	2,252
Direct General Expense	13,154	—	13,154	—	13,154	—	—	—
Taxes	10,464,909	1,949,775	2,207,948	1,436,426	6,771,522	—	251,651	55,535
Depreciation	9,712,505	391,562	5,663,500	2,048,409	3,615,091	—	3,487,744	169,699
Retirements & Cost of Retirements	437,140	34,805	330,069	123,688	206,381	—	56,004	16,262
Depletion of Producing Leaseholds	3,123,518	389,459	2,734,059	717,570	2,016,489	—	—	—
Depletion of Intangible Development Cost	19,246,443	1,435,644	17,810,799	4,826,244	12,984,555	—	—	—
Miscellaneous Income	(1,082,490)	(20,989)	(94,377)	(58,279)	(36,098)	—	(962,769)	(4,335)
Net Profits Disbursements	575,638	—	575,638	25,189	550,449	—	—	—
Profit or Loss on Sale of Capital Assets	(125,535)	—	(125,535)	(137,267)	11,732	—	—	—
Total Direct Expense	69,218,570	4,756,580	54,227,930	16,968,954	37,258,976	—	9,382,246	851,814
Percent	100.000	6.872	78.343	24.515	53.828	—	13.555	1.230
INDIRECT EXPENSE:								
Direct General Expense	8,821,980	792,722	5,864,586	1,835,146	4,029,440	—	1,909,203	255,469
Indirect Overhead	11,284,363	2,052,812	7,622,773	2,385,318	5,237,455	—	1,488,631	120,147
Total Indirect Expense	20,106,343	2,845,534	13,487,359	4,220,464	9,266,895	—	3,397,834	375,616
EXPLORATION OPERATIONS:								
Exploration and Development Expense	47,474,039	—	—	—	—	47,474,039	—	—
Return on Exploration Investment at 11%	10,828,765	—	—	—	—	10,828,765	—	—
Federal Income Tax Allowance	10,429	—	—	—	—	10,429	—	—
Total Return and Tax Allowance	10,839,194	—	—	—	—	10,839,194	—	—
Total Exploration Operations	58,313,233	—	—	—	—	58,313,233	—	—
Return on Production Rate Base at 11%	35,896,588	5,688,681	24,094,258	5,385,704	18,708,554	—	5,666,784	446,865
Federal Income Tax Allowance	34,571	5,479	23,205	5,187	18,018	—	5,457	430
Total Return and Tax Allowance	35,931,159	5,694,160	24,117,463	5,390,891	18,726,572	—	5,672,241	447,295
Total Cost of Production, Gathering and Residue Systems	$183,569,305	$13,296,274	$91,832,752	$26,580,309	$65,252,443	$58,313,233	$18,452,321	$1,674,725

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Appendix 2
Docket No. G-1148, *et al.*

PHILLIPS PETROLEUM COMPANY

RATE BASE AND RETURN
YEAR 1954

Description	Total	Oil and Gas Production Department: Natural Gas Department	Oil and Gas Production Department: Total	100% Oil Leases	Joint Products Including Cycling	Exploration and Development	Gathering System & Gasoline Facilities	Residue System
Net Investment	$404,846,456	$50,201,147	$209,530,777	$46,109,957	$163,420,820	$92,069,847	$49,202,880	$3,841,805
Percent	100.000	12.400	51.756	11.390	40.366	22.742	12.154	.948
Gross Working Capital	19,929,483	1,514,138	9,507,932	2,850,985	6,656,947	6,373,469	2,313,335	220,609
Total Rate Base	427,775,239	51,715,285	219,038,709	48,960,942	170,077,767	98,443,316	51,516,215	4,062,414
Return at 11%	46,725,353	5,688,681	24,094,258	5,385,704	18,708,554	10,828,765	5,666,784	446,865
Federal Income Tax Allowance	45,000	5,479	23,205	5,187	18,018	10,429	5,547	430
Total Return and Tax	$46,770,358	$ 5,694,160	$ 24,117,463	$ 5,390,891	$ 18,726,572	$10,839,194	$ 5,672,241	$ 449,295
Interest Calculated								
Total Consolidated Net Assets 1954	$799,360,230							
Interest Expense 1954	9,892,308							
Less:								
Interest Expense on Bonds Converted to Stock	6,149,231							
Total	$3,743,077							
Interest Expense Allowance	3,743,077 = .00468259 per dollar of Consolidated Net Assets							
Total Consolidated Net Assets	799,360,230							
Interest Expense	1,895,730	235,071	981,147	215,914	765,233	431,125	230,397	17,990

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Appendix 3
Docket No. G-1148, *et al.*

PHILLIPS PETROLEUM COMPANY

WORKING CAPITAL
YEAR 1954

Description	Total	Oil & Gas Production Department: Natural Gas Department	Oil & Gas Production Department: Total	100% Oil Leases	Joint Products Including Cycling	Exploration and Development	Gathering System & Gasoline Facilities	Residue System	Remarks

Net Investment	$404,846,456	$50,201,147	$209,530,777	$46,109,957	$163,420,820	$92,069,847	$49,202,880	$3,841,805
Percent	100.000	12.400	51.756	11.390	40.366	22.742	12.154	.948
Gross Working Capital	19,929,483	1,514,138	9,507,932	2,850,985	6,656,947	6,373,469	2,313,335	220,609
Total Rate Base	427,775,239	51,715,285	219,038,709	48,960,942	170,077,767	98,443,316	51,516,215	4,062,414
Return at 11%	46,725,353	5,688,681	24,094,258	5,385,704	18,708,554	10,828,765	5,666,784	446,865
Federal Income Tax Allowance	45,000	5,479	23,205	5,187	18,018	10,429	5,547	430
Total Return and Tax	$46,770,353	$ 5,694,160	$ 24,117,463	$ 5,390,891	$ 18,726,572	$10,839,194	$ 5,672,241	$ 449,295
Interest Calculated								
Total Consolidated Net Assets 1954	$799,360,230							
Interest Expense 1954	9,892,308							
Less:								
Interest Expense on Bonds Converted to Stock	6,149,231							
Total	$3,743,077							
Interest Expense Allowance	3,743,077	= .00468259 per dollar of Consolidated Net Assets						
Total Consolidated Net Assets	799,360,230							
Interest Expense	1,895,730	235,071	981,147	215,914	765,233	431,125	230,397	17,990

PHILLIPS PETROLEUM COMPANY

WORKING CAPITAL

YEAR 1954

Description	Total	Oil & Gas Production Department: Natural Gas Department	Oil & Gas Production Department: Total	Oil & Gas Production Department: 100% Oil Leases	Oil & Gas Production Department: Joint Products Including Cycling	Exploration and Development	Gathering System & Gasoline Facilities	Residue System	Remarks
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Total Direct, Indirect & Exploration Expenses	$136,798,952	$7,602,114	$67,715,289	$21,189,418	$46,525,871	$47,474,039	$12,780,080	$1,227,430	
Less:									
Taxes	10,548,016	1,949,775	8,207,948	1,436,426	6,771,522	83,107	251,651	55,535	Appendix Nos. 1 and 8
Depreciation	10,513,753	391,562	5,663,500	2,048,409	3,615,091	801,248	3,487,744	169,699	Appendix Nos. 1 and 8
Depletion of Producing Leaseholds	3,123,518	389,459	2,734,059	717,570	2,016,489				Appendix No. 1
Depletion of Intangible Development Costs	19,246,443	1,435,644	17,810,799	4,826,244	12,984,555				Appendix No. 1
Expired and Surrendered Leases	9,741,051					9,741,051			Appendix No. 8
Net Profits Disbursements	575,638		575,638	25,189	550,449				Appendix No. 1
Profit or Loss on Sale of Capital Assets	(125,535)		(125,535)	(137,267)	11,732				Appendix No. 1
Total Deductions	53,622,884	4,166,440	34,866,409	8,916,571	25,949,838	10,625,406	3,739,395	225,234	
Cash Requirements—Operating Expenses	$ 83,176,068	$3,435,674	$32,848,880	$12,272,847	$20,576,033	$36,848,633	$ 9,040,685	$1,002,196	
1/8 of Above (45 Days)	$ 10,397,009	$ 429,459	$ 4,106,110	$ 1,534,106	$ 2,572,004	$ 4,606,079	$ 1,130,086	$ 125,275	Exhibit No. 208
Materials and Supplies	7,771,482	963,664	4,022,208	885,172	3,137,036	1,767,390	944,546	73,674	Allocated-Net Investment
Prepayments	1,760,992	121,015	1,379,614	431,707	947,907		238,703	21,660	Exhibit No. 208
Total	$ 19,929,483	$1,514,138	$ 9,507,932	$ 2,850,985	$ 6,656,947	$ 6,373,469	$ 2,313,335	$ 220,609	Allocated-Direct Expense

Appendix 4
Docket No. G-1148, *et al.*

PHILLIPS PETROLEUM COMPANY

SUMMARY OF COST OF PRODUCTION
DIRECT AND ALLOCATED
YEAR 1954

	Natural Gas			Liquids		
	Direct	Allocated	Total	Direct	Allocated	Total
Total Direct Lease Expense	$ 4,756,580	$ 2,743,943	$ 7,500,523	$16,968,954	$34,515,033	$51,483,987
Total Indirect Expense	2,845,534	1,487,555	4,333,089	4,220,464	7,779,340	11,999,804
Return and Tax Allowance	5,694,160	4,316,731	10,010,891	5,390,891	14,409,841	19,800,732
Sub-Total Production	13,296,274	8,548,229	21,844,503	26,580,309	56,704,214	83,284,583
Exploration Operations						
Exploration Expense	—	13,090,967	13,090,967	—	31,930,089	31,930,089
Return and Tax Allowance	—	2,988,908	2,988,908	—	7,290,225	7,290,225
Sub-Total Exploration	—	16,079,875	16,079,875	—	39,220,314	39,220,314
Total	$13,296,274	$24,628,104	$37,924,378	$26,580,309	$95,924,528	$122,504,837
Unit Costs	MCF	MCF	MCF	BBLS	BBLS	BBLS
Volume	226,681,178	149,009,734	375,690,912	13,056,309	30,261,670	43,317,979
Unit Cost			10.095c			$2.83

PHILLIPS PETROLEUM COMPANY

ALLOCATION OF JOINT PRODUCTS INCLUDING CYCLING ON
THE BASIS OF RELATIVE COST
YEAR 1954

Appendix 5
Docket No. G-1148 *et al.*

Relative Cost Method

Cost of Single Product Production

Description (1)	Volume (2)	Amount (3)	Unit Cost (4)
DIRECT EXPENSE:			
100% Oil Leases	13,056,309	$16,968,954	$1.299674663
Natural Gas Department	226,681,178	4,756,580	.02098356838
INDIRECT EXPENSE:			
100% Oil Leases	13,056,309	4,220,464	$ .323250927
Natural Gas Department	226,681,178	2,845,534	.012553022
RETURN & TAX ALLOWANCE:			
100% Oil Leases	13,056,309	$ 5,390,891	$ .41289548
Natural Gas Department	226,681,178	5,694,160	.02511968

Cost of Joint Product Production

	Summary		
Description	Joint Products Including Cycling	Allocated to: Liquids	Gas
(7)	(8)	(9)	(10)
Total Direct Expense	$37,258,976	$34,515,033	$2,743,943
Total Indirect Expense	9,266,895	7,779,340	1,487,555
Return & Tax Allowance	18,726,572	14,409,841	4,316,731
Total	$65,252,443	$56,704,214	$8,548,229
Volume		30,261,670	149,009,734
Unit Cost		$1.87	5.737c

Exploration Operations						
Exploration Expense	—	13,090,967	13,090,967	—	31,930,089	31,930,089
Return and Tax Allowance	—	2,988,908	2,988,908	—	7,290,225	7,290,225
Sub-Total Exploration	—	16,079,875	16,079,875	—	39,220,314	39,220,314
Total	$13,296,274	$24,628,104	$37,924,378	$26,580,309	$95,924,528	$122,504,837
Unit Costs	MCF	MCF	MCF	BBLS	BBLS	BBLS
Volume	226,681,178	149,009,734	375,690,912	13,056,309	30,261,670	43,317,979
Unit Cost			10.095c			$2.83

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PHILLIPS PETROLEUM COMPANY

ALLOCATION OF JOINT PRODUCTS INCLUDING CYCLING ON THE BASIS OF RELATIVE COST YEAR 1954

Appendix 5
Docket No. G-1148 *et al.*

Relative Cost Method

Cost of Single Product Production

Description (1)	Volume (2)	Amount (3)	Unit Cost (4)	(5)	(6)
DIRECT EXPENSE:					
100% Oil Leases	13,056,309	$16,968,954	$1.299674663		
Natural Gas Department	226,681,178	4,756,580	.02098356838		
INDIRECT EXPENSE:					
100% Oil Leases	13,056,309	4,220,464	$ .323250927		
Natural Gas Department	226,681,178	2,845,534	.012553022		
RETURN & TAX ALLOWANCE:					
100% Oil Leases	13,056,309	$ 5,390,891	$ .41289548		
Natural Gas Department	226,681,178	5,694,160	.02511968		

Cost of Joint Product Production

	Volume	Unit Cost	Amount	Percent	Amount Allocated
DIRECT EXPENSE:					
Liquids	30,261,670	$1.299674663	$39,330,325	92.6354899	$34,515,033
Gas	149,009,734	.02098356838	3,126,756	07.3645101	2,743,943
Total			$42,457,081	100.	$37,258,976
INDIRECT EXPENSE:					
Liquids	30,261,670	.323250927	$ 9,782,113	83.947648	$ 7,779,340
Gas	149,009,734	.012553022	1,870,522	16.052352	1,487,555
Total			$11,652,635	100.	$ 9,266,895
RETURN & TAX ALLOWANCE:					
Liquids	30,261,670	.41289548	$12,494,907	76.948634	$14,409,841
Gas	149,009,734	.02511968	3,743,077	23.051366	4,316,731
Total			$16,237,984	100.	$18,726,572

Summary

Description	Joint Products Including Cycling	Allocated to: Liquids	Gas
(7)	(8)	(9)	(10)
Total Direct Expense	$37,258,976	$34,515,033	$2,743,943
Total Indirect Expense	9,266,895	7,779,340	1,487,555
Return & Tax Allowance	18,726,572	14,409,841	4,316,731
Total	$65,252,443	$56,704,214	$8,548,229
Volume		30,261,670	149,009,734
Unit Cost		$1.87	5.737c

Appendix 6
Docket No. G-1148 *et al.*

PHILLIPS PETROLEUM COMPANY

ALLOCATION OF EXPLORATION AND DEVELOPMENT COSTS
YEAR 1954

Description	Volumes	Average Weighted Btu Ratio (Millions)	Total Btu	Application of Economic Factor	Adjusted Btu	Per Cent	Allocated Explor. & Development Expense	Average (8) ÷ (2)	Allocated Return on Exploration & Develop. Invest.	Average (10) ÷ (2)	Total Cost of Explor. Operations	Average (12) ÷ (2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Gas:	*MCF*							*¢/MCF*		*¢/MCF*		*¢/MCF*
Casinghead	70,510,228	1.250	88,137,785	—	88,137,785	5.916	$ 2,808,564	3.983	$ 641,247	0.909	$ 3,449,811	4.892
Condensat	78,499,506	1.150	90,274,432	—	90,274,432	6.061	2,877,402	3.666	656,964	0.837	3,534,366	4.503
Dry, Natural Gas Dept.	226,681,178	1.025 Est.	232,348,207	—	232,348,207	15.598	7,405,001	3.267	1,690,697	0.746	9,095,698	4.013
Sub-Total	375,690,912	—	410,760,424	—	410,760,424	27.575	13,090,967	3.485	2,888,908	0.796	16,079,875	4.281
(B) Overriding Royalty Natural Gas Dept.	5,347,080	1.025 Est.	5,480,757	—	5,480,757	0.368	174,704	3.267	39,888	0.746	214,592	4.013
(C) San Juan Adjustment	69,750,000	1.025 Est.	71,493,750	—	71,493,750	4.799	2,278,279	3.267	520,173	0.746	2,798,452	4.013
Total Gas	450,787,992		487,734,931	—	487,734,931	32.742	15,543,950	3.448	3,548,969	0.787	19,092,919	4.235
Liquids:	*BBLS.*							*¢/BBL*		*¢/BBL*		*¢/BBL*
Oil	40,745,912	5.8	236,326,290	4	945,305,160	63.459	30,126,550	73.94	6,878,444	16.88	37,004,994	90.82
Condensate	2,572,067	5.5	14,146,368	4	56,585,472	3.799	1,803,539	70.12	411,781	16.01	2,215,320	86.13
Total Liquids	43,317,979	—	250,472,658	—	1,001,890,632	67.258	31,930,089	73.71	7,290,225	16.83	39,220,314	90.54
Total Gas & Liquids	— (A) —		738,207,589	—	1,489,625,563	100.000	$47,474,039	—	$10,839,194	—	$58,313,233	—

(A) Btu Ratio from Phillips Petroleum Co., Exhibit No. 310

(B) Calculation of Overriding Royalty, Natural Gas Department,
overriding Royalty, Natural Gas Department, Exhibit No. 316 $447,818
Average Price per Mcf, Natural Gas Department, Exhibit No. 359 8.375¢
Overriding Royalty of $447,818 ÷ 8.375¢ per Mcf = 5,347,080 Mcf

(C) Adjustment for, San Juan Sale to Pacific Northwest Pipeline Company
Estimated Volumes of San Juan Sale 1,395 Billion Cubic Feet
Estimated Life of Production 20 Years
Volume Assigned San Juan Sale
1,395 Billion Cubic Feet ÷ 20 Years = 69,750,000 Mcf Per Annum

Sources of Volumes:
Exhibit No. 388, Schedule 27

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Docket No. G-1148 *et al.*

PHILLIPS PETROLEUM COMPANY

EXPLORATION AND DEVELOPMENT EXPENSES
YEAR 1954

Description	Amount	Reclassification		Total
		Natural Gas Department	Oil and Gas Production Dept.	
(1)	(2)	(3)	(4)	(5)
Phillips Petroleum Company				
Drilling tool income	($7,308,354)	$ —	$ —	($7,308,354)
Clean out & miscellaneous tool income	(217,046)	—	—	(217,046)
Drilling tool expense	6,745,896	—	—	6,745,896
Clean out & miscellaneous tool expense	120,057	—	—	120,057
Undeveloped lease rentals	4,994,085	189,157	163,716	5,346,958
Taxes—exploration	83,107			83,107
Depreciation	801,248			801,248
Retirements—exploration	550			550
Cost of retirements—exploration	261			261
Dry holes—exploration and developmental	11,306,964	1,678,820	4,521,943	17,507,727
Dry holes—contributions	2,025,395	—	—	2,025,395
Expired and surrendered leases	9,479,898	234,721	24,751	9,739,370
Profit and loss from sale of capital assets	1,410	—	—	1,410
Geological, geophysical and land expense	—	3,749,475	8,801,529	12,551,004
Total Phillips Petroleum Company	28,033,471	5,852,173	13,511,939	47,397,583
Phillips Chemical Company				
Dry hole contributions	5,000	—	—	5,000
West Edmond Oil Company				
Undeveloped lease rentals	510	—	—	510
Dry holes—contribution	4,149	—	—	4,149
Expired and surrendered leases	1,682	—	—	1,682
	6,341	—	—	6,341
Phillips Offshore Oil Company				
Undeveloped lease rentals	65,115	—	—	65,115
Total Exploration Expense	$28,109,927	(A) $5,852,173	(B) $13,511,939	$47,474,039

(A) Exhibit No. 282, Page 8, Column (e), Lines 14, 15, 16 and 19.

(B) Land and geological expense from Exhibit No. 282, Page 12.
Undeveloped lease rentals, developmental dry holes, expired and surrendered leases from TR 10,138.

Appendix 8
Docket No. G-1148 *et al.*

PHILLIPS PETROLEUM COMPANY

SUMMARY OF GAS PURCHASES
YEAR 1954

Description	Gas Purchases and Content Cost Statement Volume in MCF	Adjustment to Calendar Year Basis Volume in MCF	Total 1954 Purchased Volume in MCF	1954 Purchased Volumes Adjusted To January 1956 Prices	Unit Cost Per MCF
(1)	(2)	(3)	(4)	(5)	(6)
System Gas Purchases From Leases in which Phillips Owns No Working Interest	333,364,465	3,009,457	336,373,922	$23,411,181	6.960¢
System Dry Gas Royalties and System Dry Gas Purchases of Outside Working Interests, Applicable to Leases in Which Phillips Owns An Interest	38,501,603	192,892	38,694,495	3,444,639	8.902¢
System Casinghead Gas Royalties and System Casinghead Gas Purchases of Outside Working Interests, Applicable to Leases in Which Phillips Own An Interest	31,377,131	1,538,662	32,915,793	3,464,405	10.525¢
Total	403,243,199	4,741,011	407,984,210	$30,320,225	7.432¢

Appendix
Docket No. G-1148 *et a*

PHILLIPS PETROLEUM COMPANY

GAS BALANCE AND ALLOCATION PERCENTAGES
YEAR 1954

Description		Distribution of Production						Residue Gas Sales From Systems			Total Jurisdictional Gas Sales (11) Col. (4) & Col. (10)
		Less: *Field Sales*									
	MCF	Non-Jurisdictional	Jurisdictional	Total Gas Gathered	Raw Gas Sales	Extraction Losses, Returned to Leases, etc.	Total	Non-Jurisdictional	Jurisdictional	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Gas Produced										
Dry Gas	226,681,178									
Casinghead Gas	70,510,228									
Condensate Gas	78,499,506									

System Dry Gas Royalties and System Dry Gas Purchases of Outside Working Interests, Applicable to Leases in Which Phillips Owns An Interest	38,501,603	192,892	38,694,495	3,444,639	8.902¢
System Casinghead Gas Royalties and System Casinghead Gas Purchases of Outside Working Interests, Applicable to Leases in Which Phillips Own An Interest	31,377,131	1,538,662	32,915,793	3,464,405	10.525¢
Total	403,243,199	4,741,011	407,984,210	$30,320,225	7.432¢

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PHILLIPS PETROLEUM COMPANY

GAS BALANCE AND ALLOCATION PERCENTAGES
YEAR 1954

Description (1)	MCF (2)	Distribution of Production: Less: *Field Sales* Non-Jurisdictional (3)	Jurisdictional (4)	Total Gas Gathered (5)	Raw Gas Sales (6)	Extraction "Losses, Returned to Leases, etc. (7)	Residue Gas Sales From Systems: Total (8)	Non-Jurisdictional (9)	Jurisdictional (10)	Total Jurisdictional Gas Sales (11) Col. (4) & Col. (10)
Gas Produced										
Dry Gas	226,681,178									
Casinghead Gas	70,510,228									
Condensate Gas	78,499,506									
Total		375,690,912	31,370,014	65,159,256	279,161,642					
Per cent		100.0000	8.3500	17.3438	74.3062					
Gas Purchased										
Outside Leases	336,373,922									
Outside Interest in Phillips Leases:										
Dry Gas	38,694,495									
Condensate & Casinghead Gas	32,915,793									
Total		407,984,210			407,984,210					
Total Produced & Purchased		783,675,122	31,370,014	65,159,256	687,145,852	18,845,896	76,017,914	592,282,042	166,262,345	426,019,697	491,178,953
Per Cent								100.0000	28.0715	71.9285	
Btu per Cubic Foot					1151	1151		1063			
Total Btu (Millions)					790,904,876	21,691,626	139,617,439	629,595,811			
Per Cent					100.0000	2.7426	17.6529	79.6045			

PHILLIPS PETROLEUM COMPANY
JURISDICTIONAL COST OF SERVICE
YEAR 1954

Description	Volume	Total Cost of Gas	Distribution of Production & Exploration Costs: Field Sales Non-Jurisdictional	Field Sales Jurisdictional	Delivered to Gathering Systems	Raw Gas Sales	Balance Col. (6)-Col. (7)	Less: Liquids Extracted	Total Cost of System Sales
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Per Cent		100.0000	8.3500	17.3438	74.3062	Col. (6) × 2.7426%		Col. (8) × 17.6529%	Cols. (6)-Col. (9)
COST OF GAS PRODUCTION & EXPLORATION									
Direct and Allocated	375,690,912	$37,924,378	$3,166,686	$6,577,528	$28,180,164				
Purchased Gas	407,984,210	30,320,225			30,320,225				
Total Cost of Produced and Purchased Gas		$68,244,603			$58,500,389	$1,604,432	$56,895,957	$10,043,786	$48,456,603
Gathering System and Compressing Facilities		18,452,321			18,452,321	506,073	17,946,248	3,168,033	15,284,288
Residue System		1,674,725			1,674,725				1,674,725
Sub-total		$88,371,649			$78,627,435	$2,110,505	$74,842,205	$13,211,819	65,415,616
Raw Gas Sales						($2,110,505)			$ 2,110,505
Total									$67,526,121

Jurisdictional Sales from Systems (Column (12))
Jurisdictional Sales From Leases (Column (5))
Regulatory Commission Expense

Total Jurisdictional Cost of Service

COST PER M.C.
$55,548,054 ÷ [1]

[1] See Appendix 9

Appendix 10
Docket No. G-1148 *et al.*

PHILLIPS PETROLEUM COMPANY
JURISDICTIONAL COST OF SERVICE
YEAR 1954

Volume	Total Cost of Gas	Distribution of Production & Exploration Costs: Field Sales Non-Jurisdictional	Field Sales Jurisdictional	Delivered to Gathering Systems	Raw Gas Sales	Balance Col. (6)-Col. (7)	Less: Liquids Extracted	Total Cost of System Sales	Sales Non-Jurisdictional	Sales Jurisdictional
(2)	(3) 100.0000	(4) 8.3500	(5) 17.3438	(6) 74.3062	(7) Col. (6) × 2.7426%	(8)	(9) Col. (8) × 17.6529%	(10) Cols. (6)-Col. (9)	(11) 28.0715%	(12) 71.9285%
375,690,912	$37,924,378	$3,166,686	$6,577,528	$28,180,164						
407,984,210	30,320,225			30,320,225						
	$68,244,603			$58,500,389	$1,604,432	$56,895,957	$10,043,786	$48,456,603		
	18,452,321			18,452,321	506,073	17,946,248	3,168,033	15,284,288		
	1,674,725			1,674,725				1,674,725		
	$88,371,649			$78,627,435	$2,110,505	$74,842,205	$13,211,819	65,415,616		
					($2,110,505)			$ 2,110,505		
								$67,526,121	$18,955,595	$48,570,526

Jurisdictional Sales from Systems (Column (12))	$48,570,526
Jurisdictional Sales From Leases (Column (5))	6,577,528
Regulatory Commission Expense	400,000
Total Jurisdictional Cost of Service	$55,548,064

COST PER M.C.F.
$55,548,054 ÷ [1] 491,178,963 M.C.F. 11.309¢

[1] See Appendix 9

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Before Commissioners: Jerome K. Kuykendall, Chairman; Frederick Stueck and Arthur Kline.

Statement of General Policy No. 61-1

Establishment of Price Standards to be Applied In Determining The Acceptability of Initial Price Proposals and Increased Rate Filings by Independent Producers of Natural Gas

(Issued September 28, 1960)

This statement establishing rate standards for independent producers of natural gas is issued on our own motion and is based on our experience gained after six years of regulation of independent producers under the Natural Gas Act. By this statement and the appended area price schedules we will set standards for initial and increased rate filings by producers for the sale of natural gas into interstate commerce. These standards will serve as a guide to us and to interested parties in determining whether proposed initial rates should be certificated without a price condition and whether proposed rate changes should be accepted or suspended.

Since the Supreme Court's 1954 decision in *Phillips Petroleum Company* v. *Wisconsin*, 347 U.S. 674, holding that under the Natural Gas Act the Commission has jurisdiction over the interstate transportation and interstate sale for resale of natural gas by independent producers, and that such producers are "natural-gas companies" under the Act, the Commission's regulatory task has increased enormously in size and difficulty. In contrast to the regulation of less than 200 pipeline companies prior to the *Phillip* case, under this decision Commission regulation extends to several thousand independent producers of

natural gas. Although this producer segment of the natural gas industry differs from the pipeline transmission portion in fundamental particulars, its multiplicity of sales and services are now required to be covered by many thousands of rate and certificate filings under the Act.

This ever-growing volume of additional rate and certificate filings has placed an increasing burden not only on this Commission and other regulatory commissions, but on all those—consumers, producers, pipeline companies, and distributing companies as well—whose interests we must consider in administering the Act. It is essential, particularly in the interest of the consumer for whose protection the statute was enacted, that means be found for making the most effective use possible of the Commission's limited facilities in discharging the new and additional duties called for by the regulation of producers of natural gas. In our opinion, the price standards established by this statement will aid in effectively applying the

provisions of the Act to independent producers on a simple, clear and administratively feasible basis, and in a manner fair to all whose interests are affected by Commission regulation. Our many reasons for establishing these maximum acceptable rates as opposed to establishing rates based on a full cost-rate base hearing for every rate filing made by producers are set forth at considerable length in our opinion No. 338, *Phillips Petroleum Co.*, Docket No. G-1148, et al., pp. 5 thru 12, issued on this date.

Some further explanation is required of certain aspects of these area rate levels. The geographical areas which we have used are convenient and well known. They are not necessarily in complete accord with geographical and economic factors which may be relevant to the establishment of pricing areas. As experience and changing factors may indicate, we will change or alter these areas from time to

time in order to eliminate such inequities as may appear to exist because of our use of geographical boundaries.

In arriving at the price levels for the various areas set forth in the appendix to this statement, we have considered all of the relevant facts available to us. Such consideration included cost information from all decided and pending cases, existing and historical price structures, volumes of production, trends in production, price trends in the various areas over a number of years, trends in exploration and development, trends in demands, and the available markets for the gas. Of necessity, we have not set forth the adjustments to these prices which must be made to take into account every possible provision of every contract which may affect the actual price, such as Btu adjustments, conditions of delivery, etc. The relevance of such adjustments to the basic contract price and the appropriate established price standard must be considered as each filing is made. As it becomes apparent that certain adjustments have general applicability in a specific area, the area price standard will be revised and set forth in greater detail with regard to the exact sale conditions to which the rate applies. We should, however, make it clear that these present price standards apply to pipeline quality gas as that term is generally understood in each area and, except for the Louisiana prices, are inclusive of all taxes.

Two price standards are set for each area. Initial prices in new contracts are, and in many cases by virtue of economic factors, must be higher than the prices contained in old contracts. For this reason, we have found it advisable to adopt two schedules of prices, one pertaining to initial prices in new contracts and one pertaining to escalated prices in existing contracts. It is anticipated that these differences in price levels will be reduced and eventually eliminated as subsequent experience brings about revisions in the prices in the various areas.

It will be noted that we have omitted listing an initial price level for sales from Southern Louisiana and Mississippi. The proper initial price level for these areas is currently the subject of two hearings pursuant to Supreme Court decisions. *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378; *Public Service Commission* v. *F.P.C.*, 361 U.S. 195, F.P.C.

Docket Nos. G-11024, *et al.*, and G-13143, *et al.*, respectively. Clearly, in light of these cases, it would not be proper at this time for us to announce an initial rate level for these areas prior to a final determination of these cases.

These price levels, as announced by Appendix A attached to this statement, are for the purpose of guidance and initial action by the Commission and their use will not deprive any party of substantive rights or fix the ultimate justness and reasonableness of any rate level. As with the areas, the prices will be adjusted from time to time as such facts as may come before us compel such adjustments. For the present, and in the absence of compelling evidence calling for other action by us, proposed initial sales of natural gas by independent producers which include rates higher than those indicated in the appendix attached to this statement shall be denied a certificate or certificated only upon the condition that lower rates be filed, and all rate changes filed under existing contracts which call for a rate exceeding the indicated price level in the attached appendix to this statement shall be suspended.

Where a proposed price exceeds the indicated rate level and is therefore conditioned or suspended we will, in determining whether the higher price is justified, not necessarily consider only the financial requirements of the individual producer proposing the price but will consider all of the above elements relevant to the industry generally in the area concerned. Similar evidence will also be required

from purchasers or their customers who object to any of the price levels or any specific price. Our determination will be in the nature of setting a price for the gas itself from any source questioned and not necessarily a price applicable solely to the party proposing some other price. In this connection we urge that all parties who have any interest in changing an area price join in such a proceeding leading to a determination of a proper revision, if any, in an area price or in the geographical area itself. As there will undoubtedly be numerous parties with an interest in such a proceeding full use should be made of prehearing procedures to reduce the factual issues and consolidate factual presentations to eliminate repetition and duplication of evidence. Because of the impossibility of giving detailed instructions for every proceeding, the precise course of each hearing and the admissibility and relevant weight of each type of evidence must be determined as hearings proceed and we expect to issue additional policy statements from time to time clarifying various aspects of these procedures and principles. The new area rate determinations resulting from such proceedings will represent final determinations of just rates for the areas involved as of the date of the decision and for prior periods.

By the Commission.

APPENDIX A
(To Statement of General Policy No. 61-1)

AREA PRICE LEVELS FOR NATURAL GAS SALES BY INDEPENDENT PRODUCERS

(All Rates at 14.65 PSIA)

Area	Initial Service Rates/MCF	Increased Rates/MCF
Texas		
District No. 1	15.0¢	14.0¢
District No. 2	18.0¢	14.0¢
District No. 3	18.0¢	14.0¢
District No. 4	18.0¢	14.0¢
District No. 5	14.0¢	14.0¢
District No. 6	15.0¢	14.0¢
District No. 7-b	14.0¢	11.0¢
District No. 7-c	16.0¢	11.0¢
District No. 8	16.0¢	11.0¢
District No. 9	14.0¢	14.0¢
District No. 10	17.0¢	11.0¢
Louisiana		
Southern	not determined	13.7¢ (14.0¢ at 15.025 psia)
Northern	16.6¢ (17.0¢ @ 15.025 psia)	13.7¢ (14.0¢ at 15.025 psia)
Mississippi	not determined	13.7¢ (14.0¢ at 15.025 psia)
Oklahoma		
Panhandle Area	17.0¢	11.0¢
Other	15.0¢	11.0¢
Carter-Knox	16.8¢	11.0¢
Kansas	16.0¢	11.0¢
New Mexico		
Permian Basin	16.0¢	11.0¢
San Juan Basin	12.7¢ (13.0¢ @ 15.025 psia)	12.7¢ (13.0¢ at 15.025 psia)
Colorado	14.6¢ (15.0¢ @ 15.025 psia)	12.7¢ (13.0¢ at 15.025 psia)
Wyoming	15.0¢	12.7¢ (13.0¢ at 15.025 psia)
West Virginia	26.8¢ (28.0¢ @ 15.325 psia)	23.9¢ (25.0¢ at 15.325 psia)

Application of State of Wisconsin and Public Service Commission of Wisconsin for Rehearing

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Now Comes the State of Wisconsin and Public Service Commission of Wisconsin, pursuant to the provisions of Section 19(a) of the Natural Gas Act and Section 1.34 of the Rules of Practice and Procedure of the Federal Power Commission, and for their application for rehearing from the determination of the Federal Power Commission issued on September 28, 1960 (Opinion No. 338) in the above captioned proceedings, allege as follows:

I.

That the State of Wisconsin is one of the states of the United States, and the Public Service Commission of Wisconsin is an agency of said state deriving its powers from statutes enacted by the Legislature of Wisconsin, having powers and duties given it by Chapter 195 and 196, Wisconsin Statutes, which include, among other things, the power and duties to regulate rates charged by and the adequacy of service furnished by public utilities in Wisconsin, including those which deliver

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and sell natural gas to the public for ultimate public consumption, to the end that such public utilities deliver and furnish reasonably adequate natural gas service to the public at just and reasonable rates.

Much of the natural gas sold in Wisconsin is purchased by local distribution utilities from Michigan Wisconsin Pipe Line Company, which in turn purchases up to 343,000 Mcf of natural gas from Phillips Petroleum Company at the Sherman Gasoline Plant in Hansford County, State of Texas. Phillips also sells substantial quantities of gas to Northern Natural, Permian Basin, Natural Gas Pipeline Company of America and Peoples Gulf Coast. Some of this gas is delivered to Wisconsin customers of Northern Natural and Natural Gas Pipeline Company of America.

The Public Service Commission of Wisconsin is a "state commission" within the meaning of the term as used in Sections 2(8), 13 and 15 of the Natural Gas Act and Section 1.8 of the Rules of Practice and Procedure of the Federal Power Commission.

Both the State of Wisconsin and Public Service Commission of Wisconsin represent the consuming public in Wisconsin in matters before the Federal Power Commission so as to have supplied to such consumers reasonably adequate natural gas service and facilities at just and reasonable rates.

The State of Wisconsin is also a consumer of natural gas purchased from Madison Gas & Electric Company among others, which in turn purchases said gas from Michigan Wisconsin Pipe Line Company.

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The State of Wisconsin and Public Service Commission of Wisconsin are intervenors in the above-captioned dockets and participated therein, submitting evidence and argument.

II.

For their grounds for rehearing the State of Wisconsin and Public Service Commission of Wisconsin state that the Federal Power Commission (FPC) and the members of the Federal Power Commission (FPC) who participated in the decision issued September 28, 1960 denominated Opinion No. 338, erred in issuing said opinion in each of the following respects:

(1) By including (pages 5 to 11, inclusive) statements as to policies to be followed in regulating the rates of independent producers.

The inclusion of such material is error and the same should be stricken because the issue in this case is to determine whether the jurisdictional rates and charges or classifications demanded, observed, charged or collected by Phillips, or any rules, regulations, practices or contracts affecting them, are unjust, unreasonable, unduly discriminatory or preferential. Natural Gas Act §§ 4, 5. This must be determined on the basis of the facts and circumstances disclosed by the record in this proceeding. Administrative Procedure Act §§ 7(d), 8. What might or might not be done in some other case must be determined on the basis of the record in that case.

The material at pages 5 to 11, inclusive, of Opinion No. 338 should also be stricken for the reason they are gratuitous statements not binding on the Federal Power Commission

or any member thereof in a subsequent rate-case. A rate order is not *res adjudicata* and every rate order may be superseded by another order. *Tagg Bros. & Moorhead* v. *United States*, 280 U.S. 420, 74 L. Ed. 524.

Such material is in any event unnecessary as, in any event, Opinion No. 338 purports to determine the cost

of service for Phillips on a cost basis which, as the Presiding Examiner pointed out (page 13 of Opinion), was a method urged by intervenors, the Staff and Phillips.

The Federal Power Commission also erred in saying that regulation of independent producers on the basis of costs is not feasible. See Presiding Examiner's decision pp. 12-14 for material supporting our position. In any event, cost is required as a starting point at least, by law. *Detroit* v. *Federal Power Comm.*, 230 F. (2d) 810; *Episcopal T.S.* v. *Federal Power Comm.*, 269 F. (2d) 228. The Federal Power Commission misinterprets and misconstrues *Forest Oil Corporation* v. *Federal Power Comm.*, 263 F. (2d) 622, which when properly read clearly in accord with *Bel Oil Corp.* v. *Federal Power Comm.*, 255 F. (2d) 548, which in turn does not lay down a different rule than *Detroit* v. *Federal Power Comm., supra.*

The so-called "policy statement" (page 11) is in excess of the statutory powers of the Federal Power Commission. Legally it is a mere *ex parte* statement by members of the Federal Power Commission based on no record and made without opportunity for petitioners or any other party to be heard. The figures selected are arbitrary and capricious and represent

administrative fiat. Said policy statement has no evidentiary suport in the record in this case, and cannot legally be made in this case because it is beyond the issues in this case. It cannot be considered as a rule because the Federal Power Commission has not complied with the statutory requirements for rule making. Administrative Procedure Act § 4.

As a practical matter, however, such statement will raise producer prices in areas where they operate, up to the maximum price stated, and hence will create a "price plateau" for natural gas in the areas involved without any

consideration being given as to the cost to the various producers therein and will constitute a change in rate without complying with Sections 4, 5 of the Natural Gas Act. This would be prejudicial to the consumers of natural gas. Cf. *Atlantic Refining Co.* v. *Public Serv. Comm. of New York*, 360 U.S. 378, 3 L. Ed. (2d) 1312.

(2) By concluding the increased cost of gas purportedly called for under percentage type casinghead contracts between Phillips and its suppliers is proper, although no dollar amount for such item is determined. Opinion No. 338, pp. 15-17.

The allowance of this or any other dollar amount for this item is error because the said gas suppliers are each a "natural gas company" (*Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672) subject to regulation by the Federal Power Commission, and said increase constitutes a change in rate under Section 4(d), Natural Gas Act, and can be made only after compliance therewith and approval of the Federal Power Commission, and is also subject to Section 5 of the Act.

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Bel Oil Corp. v. *Federal Power Comm.*, 255 F. (2d) 548, 554; *Episcopal T.S.* v. *Federal Power Comm.*, 269 F. (2d) 228, 231-2, 235.

The Federal Power Commission cannot avoid statutory requirements by adoption of a rule such as Section 154.91(e). The case of *Sun Oil Co.* v. *Federal Power Comm.*, 256 F. (2d) 233, is not applicable. Among other things, there no injury had been shown. Allowance of such an increase as here proposed without meeting the standards of Sections 4 and 5 of the Act would injure consumers.

(3) By reducing interest deduction for tax purposes from $9,892,308 (actual recorded company-wide interest

expense for 1954) to $3,743,077, which latter amount becomes $1,895,730 when allocated to the Natural Gas Department and Oil and Gas Production Department. Pages 17, 18.

(4) By including in the estimate for joint production expenses (exclusive of exploration) the amount of $18,726,572 for return and tax incentives, as set forth in Appendix 5. Page 19.

The Federal Power Commission erred in allowing the $18,726,572 representing return and tax incentive, based on a return allowance of 11% which, for reasons stated in (10), *infra*, is in excess of a proper rate of return, which should not exceed 9.16% (based on 2.76% cost of debt and 10% for common equity) and on basis of A. R. Colbert testimony and exhibit, 7¾%. See paragraph (9), *infra*.

(5) By including in exploration and development costs

the amount of $10,839,194 for return and taxes. Page 23.

The Federal Power Commission erred in allowing $10,839,194 for return and taxes. The return allowance used is 11% (Appendix 1), which is an erroneous rate of return for reasons stated in (9), *infra*.

(6) By allocating exploration and development costs on the basis of the Btu. content of gas and oil to which an "economic factor" of 4 is applied to the Btu. content of a barrel of oil (42 gallons) so that it is considered the cost relationship of finding 1 Mcf of gas to 1 barrel of oil will be 1 to 24. Page 29.

The Federal Power Commission erred in adopting such method of allocation because the record contains no evidence which supports use of a so-called "economic factor" of 4. This is recognized by the Federal Power Commission (p. 29) when it states its result is based on an exercise of "administrative judgment" based on the record but that

the record did not lead us to the precise conclusion. Additionally the FPC in utilizing a 4 to 1 economic weighting factor, in effect, created a new pricing relationship between gas and oil which is not based on any facts of record or any thing more than a desire to further enhance the gas production end of the joint oil and gas business at an expense of the gas consuming public.

If this factor is eliminated (as it must be because there is no evidence supporting its use—Administrative Procedure Act § 7(c)), any allocation based on the Btu. content

of the fuels must be rejected because of the difference in form and methods of utilization between the two fuels. (Pettyjohn, Tr. 95:12652 to 95:12706, and Exhibits 348 to 352.)

(7) By adopting a year-end rate base. Page 36.

The Federal Power Commission erred in the above respect because it weighs in for a full year the cost of plant additions made for such year, whereas revenues and expenses against which the investment has been matched are not adjusted as to reflect the operation of facilities installed on a full year basis. Van Scoyoc, Tr. 101:13370. The proper method is to use an average year rate base and thus match rate base with revenues and expenses. Use of a year-end rate base produces additional return.

(8) By including in rate base $8,430,758 representing net investment in San Juan producing leases which were transferred to Pacific Northwest Pipe Line Corporation in November 1955. Page 36-7.

The Federal Power Commission erred in the above respect because even under regulation on a going-concern basis there have been and will continue to be in the future other "San Juan situations." The immediate reimbursement of the investment and the continuing overriding

royalties are considered nonoperating revenues. Under cost regulation customers are required to carry the burden of all costs associated with jurisdictional revenues. Certainly it would be basically unfair to set jurisdictional revenues at a level which would require a continuing return on property already sold and from which the continuing overriding royalties were absorbed as nonjurisdictional

revenues. The inherent unfairness of such an arrangement speaks for itself. The San Juan properties should be summarily excluded from the rate base. Substituted property should be included only when specifically denominated and identified.

Here the Federal Power Commission does not purport to proceed on the going-concern basis, since it states (p. 30) it is not determining rates for the future, and in one instance (p. 17) refused to make an adjustment because it said it was not determining future rates. Under such circumstances this is all the more reason why the amount representing the San Juan leases should not be included in the rate base.

Further, the Federal Power Commission stated (p. 17) it makes adjustments in the actual test year data for known changes after the end of the test year, and did so in one instance (pages 17, 18). If the Federal Power Commission is going to make adjustments of known changes after the end of the test year in favor of Phillips, it should also make an adjustment for the San Juan item which goes the other way, or at least give credit for normal revenues which could be expected from such or equivalent properties.

(9) By allowing Phillips a rate of return of 11%. Pages 39-48, inclusive.

The Federal Power Commission erred:

a. In confusing the physical risk of producing gas with the financial risk assumed by investors. (P. 42) There is a physical risk in discovering and producing gas, but it is compensated for by the allowance of the cost of exploration development and production as an expense to Phillips in deter-

mining its cost of service. This eliminates this item as a part of the financial risk, assuming that Phillips can sell its gas, and in this respect it stands in no different position than a pipeline transmission company or local distribution company. Colbert, Tr. 98:12966-7. Thus, the Federal Power Commission erred in stating (p. 42) "Nevertheless, production of gas creates risk in spite of the willingness of investors to purchase the securities of producers, and this risk must be taken into consideration in arriving at a fair rate of return. We should not base our findings wholly upon a passing tendency of investors." The Federal Power Commission erred because the actual conduct of investors, as demonstrated by earnings price ratios, shows their evaluation of the *financial* risk, including the physical risk of discovery and producing gas as well as all other risks and factors affecting the value of the stock. Tr. 112:14912. Contrary to the suggestions appearing at page 43 second paragraph, the earnings price ratios do reflect *all* factors affecting a security, plus or minus, which motivate an investor, since these factors directly reflect the price the investor is willing to pay for the common stock or other security of any company. Smith, Tr. 83:11210-11. Phillips' stock is listed on the New York Stock Exchange and this is true so far as its common stock is concerned.

b. In refusing to consider the amount of $19,162,355 (deferred Federal income tax liability under Section 168, I.R.C.) as an interest-free loan so as to reduce the cost of debt capital to 2.76%. Page 43. There can be no quarrel

with the proposition that this is interest-free capital. It comes

from money collected from rate payers. It is unfair to permit Phillips to exact higher rates from customers on capital contributed by customers at no cost to Phillips.

c. In increasing the cost of equity capital from 10%, which the Federal Power Commission indicated would be reached by earnings price ratios (pp. 46-7), by an additional 2% as an alleged incentive for the continued exploration and production of gas. This can be done only if the record shows that the amount allowed is needed for such purpose and is no more than needed. *Detroit* v. *Federal Power Comm.*, 230 F. (2d) 810. The record here contains no such evidence.

d. For the above reasons the Federal Power Commission erred in concluding (p. 48) an allowance of 12% for common equity would be fair and reasonable.

e. The proper allowance should not exceed 9.16% (based on 2.76% cost of debt and 10% for common equity) and on basis of testimony of A. R. Colbert (Tr. 98:12948-12973; 112:14871; 112.14876-14959; 112:14960 and Exhibit 369) should not exceed 7¾%.

(10) By determining the cost of service for Phillips, on the basis of a 1954 test year, to be $55,548,054 subject to adjustment for Phillips' purchased gas costs, royalties and gathering taxes. P. 49.

The figure obtained by the FPC as representing Phillips' cost of service on the basis of a 1954 test year, is affected by the errors previously noted. Elimination of such errors will reduce the cost of service below that determined by the FPC.

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(11) By (a) not holding the spiral escalation clauses in the contracts between Phillips and Michigan Wisconsin Pipe Line Company, El Paso Natural Gas Company and Panhandle Eastern Pipe Line Company void as a matter of law, and (b) in concluding that such clauses provide contractual consent to rate increases under the doctrine of *United Gas Company* v. *Mobile Gas Corporation*, 350 U.S. 332. Pages 52-3.

The Federal Power Commission erred in not holding the aforesaid spiral escalation clauses void as a matter of law, because said clauses purport to authorize increases in rates under circumstances inconsistent with the provisions of the Natural Gas Act, in that they would purport to effect a change in rate between Phillips and its pipeline customers without compliance with Sections 4 or 5 of the Natural Gas Act. The decision of the Federal Power Commission in *Re Michigan Wisconsin Pipe Line Company*, G-1678, G-1996, Opinion No. 275, mimeographed edition pp. 39-40, to the effect that the spiral escalation clause in the contract between Phillips and Michigan-Wisconsin is inconsistent with the Natural Gas Act and contrary to the public interest as a matter of law, should be followed and the Federal Power Commission erred in not doing so. Any clause (such as a spiral escalation clause) in a contract which purports to operate contrary to a statute is void as a matter of law. 12 *Am. Jur.* (Contracts) § 158, *et seq.* Nothing in *United Gas Pipe Line Co.* v. *Memphis L.G. & W.D.*, 358 U.S. 103, 3 L. Ed. (2d) 153, is to the contrary. To conclude, as does the Federal Power Commission, that a spiral escalation

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clause can constitute a consent under Section 4 of the Natural Gas Act, is tantamount to saying that a contract provision (which legally can have no effect because any rate increase purportedly called for thereby is subject to com-

pliance with, justification under and approval of the Federal Power Commission under the Natural Gas Act) constitutes a consent to a change in rates in the manner authorized by statute. There is no language in such clause that justifies the conclusion that such consent has been given, and further since such clauses are standing alone legally inoperable since enactment of the Natural Gas Act (*Bel Oil Corp. v. Federal Power Comm.* (C.A. 5), 255 F. (2d) 548, 554) and do not of themselves constitute proof establishing the right to any increase purportedly called for thereunder, they cannot legally be considered as affording a consent. See, *Episcopal T.S.* v. *Federal Power Comm.* (U.S.App.D.C.), 269 F. (2d) 228, at 235.

(12) By issuing an order that did not confine itself to any thing more than terminating proceedings in dockets where the rate in force or proposed did not exceed the cost of service as properly determined. Pages 50-56.

The Federal Power Commission erred in ordering that the proceedings in the various dockets involved be terminated, with the exception of dockets G-111217 and G-10883 which were made the subject of special orders in paragraphs (B) and (C), and in discharging the obligation of Phillips to refund excess charges respecting the dockets which were terminated.

There are certain dockets (G-3175, G-4333, G-6621,

G-8695, G-8883, G-10359, G-11125) at least where the rate under inquiry exceeded the cost of service even as computed by the Federal Power Commission. We submit the Federal Power Commission erred in not confining its order terminating proceedings to those dockets where the cost of service (after giving effect to the matters herein stated in this petition for rehearing) exceeded the cost of service (11.039¢ Mcf even on basis of the Federal Power Commission determination which we say is high). The necessary

assumption made in terminating the proceedings in dockets where the rate under inquiry exceeded the cost of service, is that the amount of any excess is offset by subsequent increase in cost so that at a subsequent time rates which exceed the cost of service as determined thereafter will be justified. We submit the Federal Power Commission erred in making and acting on such an assumption, because in so doing it (a)necessarily goes beyond the record in this case contrary to the Administrative Procedure Act § 7(c), as is shown by statements at page 51, (b) permits higher rates to become effective without showing that they are justified, adopting in effect the same procedure as was attempted in *Re Shamrock Oil and Gas Corp.*, 31 PUR (3d) 84, which procedure we assert is erroneous and which case is on review in the United States Court of Appeals for the District of Columbia Circuit, which has the effect of placing pipeline customers and consumers in the position of being faced with increases which have not been justified on any thing other than administrative fiat, consisting of (p. 54) "the area pricing standards announced at this time." Such standards are without legal effect, are based on

no record, and were promulgated without giving any one an opportunity to be heard. The Federal Power Commission recognizes (p. 51) this will leave in effect Phillips' "contract structure," thus indicating acceptance of contract prices, which is an abdication of regulation by the Federal Power Commission. Also contract prices are not sufficient to justify a change in rate. *Episcopal T.S.* v. *Federal Power Comm.* (U.S.App.D.C.), 269 F.(2d) 228, 235, *et seq.*

WHEREFORE, the State of Wisconsin and Public Service Commission of Wisconsin request that this application for rehearing be granted and that the Federal Power Com-

mission correct its Opinion No. 338 in the respects above stated.

Respectfully submitted,

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October 24, 1960.

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Petition for Rehearing on Behalf of the People of the State of California and Public Utilities Commission of the State of California

Come now the People of the State of California and the Public Utilities Commission of the State of California (California), interveners herein, and being aggrieved by the Opinion and Order Determining Cost of Service and Terminating Proceedings (Opinion No. 338) issued by the Federal Power Commission (Commission) in the above-entitled proceedings on September 28, 1960, hereby apply for rehearing and stay of said Opinion and Order pursuant to the provisions of Section 19(a) of the Natural Gas Act (Act of June 21, 1938, c. 556; 52 Stat. 821, 831; 15 USC § 717r) and pursuant to Section 1.34 of the Commission's Rules of Practice and Procedure.

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INTRODUCTION

California takes no position at this time regarding the opinions expressed by the Commission in Opinion No. 338 under the title "Regulation of Natural Gas Producers' Prices" (mimeo., pp. 5-12) wherein the Commission announces its conviction that regulation of such prices under the cost of service method is unworkable and productive of ridiculous results and wherein the Commission announces its intention to regulate producer prices hereafter by use of an area pricing method as is more particularly described in the Commission's Statement of General Policy No. 61-1 issued on the same date as it issued its opinion in the instant proceedings. Because the Commission employed the

traditional cost of service method in reaching its findings and conclusions in the instant proceedings (mimeo., p. 13) its comments concerning the future course of producer rate regulation are therefore not material here. California reserves the right, however, to challenge such comments as are contained in that portion of Opinion No. 338 indicated above as well as the Statement of General Policy No. 61-1 in any future proceeding wherein the Commission's views therein expressed may be material to its determination of rates under the Natural Gas Act.

The following grounds for rehearing and specifications of error are made in support of this petition.

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I. In terminating the Section 5(a) investigation in Docket No. 1148, the Commission failed to make a determination that the rates of Phillips Petroleum Company (Phillips) are just and reasonable as it is required to do by said section of the Natural Gas Act.

The Commission states (mimeo., pp. 50-51):

> "Having determined Phillips' cost of service, the next step would ordinarily be to alter Phillips' rates to reflect this cost of service. We are authorized in an investigation under Section 5(a) to determine rates prospectively * * *.
>
> * * * * * *

"The present proceeding involves an investigation of Phillips' rates on the basis of a record including evidence on the alternate test years 1954 and 1956 of which we chose 1954 in accordance with the decision of the examiner. *From our knowledge of the industry, it is clear enough that costs and prices of gas in the field have greatly increased since that time.* * * * Therefore we do not deem it appropriate to prescribe or require that Phillips file rates for the future based upon the present record. * * *

"As a result we shall terminate the rate investigation proceedings in Docket No. G-1148 under Section 5(a). Phillips' customers will not be substantially injured, for Phillips' rate filings have been subject to our continuing surveillance and many large increases filed by it have been suspended under Section 4(e) of the Act and are currently the subject of proceedings before us. * * *" (Emphasis supplied.)

Inasmuch as a Section 5(a) investigation is the only means provided by the Natural Gas Act for review by the Commission of initial certificated prices, the Commission's action in terminating the Section 5(a) investigation in this proceeding

may be tantamount to a conclusion that such initial prices are reasonable. However, the Commission makes no finding whatsoever that such initial prices are just and reasonable as required by Section 5(a) of the Act.

In lieu of such a finding, the Commission merely refers to its opinion based on its "knowledge of the industry" that both "costs and prices of gas in the field have greatly increased" since 1954. In basing its decision to terminate the Section 5(a) investigation on such an opinion, for which the Commission itself claims no support in the record, the

Commission has failed to make any finding based on evidence of record that initial certificated prices since 1954 are just and reasonable.[1]

The Commission points out that consumers will not be "substantially injured" because Phillips' rate filings have been subject to the Commission's "continuing surveillance". However, the very surveillance to which the Commission alludes, as far as initial prices are concerned, is to be found only within the framework of a Section 5(a) investigation. It is

such an investigation and such a surveillance that the Commission has determined to terminate by its order contained in Opinion No. 338.

Under these circumstances, consumers are not afforded any relief from unreasonable initial prices. Moreover, initial certificated prices are not subject to refund as are rate increase filings which are subject to the provisions of Section 4(e) of the Act. In this connection we think the following language from the Supreme Court's opinion in the CATCO case.[2] is pertinent.

> ". . . the delay incident to determination in § 5 proceedings through which initial certificated rates are reviewable appears nigh interminable. Although *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, 98 L.Ed. 1035, 74 S. Ct. 794, was decided in 1954, cases instituted under § 5 are still in the investigative stage. This long delay, without the protection of refund, as is possible in a § 4 proceeding, would provide a windfall for the

[1] Compare the Commission's statement that the rates involved in the Section 4(e) proceedings, which are also terminated, "have produced revenues less than Phillips' cost of service during the periods that they were in effect." (Mimeo., p. 51.) The Commission makes no such claim relative to the rates which were reviewable only in the Section 5(a) proceeding.

[2] *Atlantic Refining Co.* v. *Public Service Commission of the State of New York*, 360 U. S. 378, 389 79 S. Ct 1246, 3 L.Ed. 2d 1312 (1959).

natural gas company with a consequent squall for the consumers. *This the Congress did not intend.*" [Emphasis supplied.]

The Commission also points out that "consumers will receive the protection of our area pricing standards announced at this time". Even so, it is inescapable that in terminating the Section 5(a) investigation, the Commission has failed to

fix just and reasonable rates for Phillips as it has the duty to do under that section of the Natural Gas Act.

II. The Commission erred in failing to find that the spiral escalation clauses in Phillips' contracts are "so derogatory of the public interest as to be void as a matter of law." (Mimeo., p. 22.)

Spiral escalation clauses, as well as favored nation clauses, result in rate increases conditioned on a fortuitous event which does not bear any relationship whatsoever to an increase in the producer's costs. California contends that no rate may be found to be just and reasonable within the meaning of Section 4(a) of the Natural Gas Act if that rate does not bear a reasonable relationship to costs. Consequently rate increase filings predicated on spiral escalation clauses in gas sales contracts *are* so derogatory of the public interest expressed in the Natural Gas Act as to be void as a matter of law.

It would appear that, at least in a sense, the Commission agrees. It states: "* * * we do not approve of such clauses in principle."[3]

[3] Mimeo., p. 22. Although the Commission does not specify the "principle" that it has in mind, the time honored regulatory principle that rates must bear a reasonable relationship to costs immediately suggests itself.

The Commission, however, is apparently dissuaded from holding such clauses to be void as a matter of law owing to its interpretation of the opinion of the Supreme Court of the United States in *United Gas Pipe Line Co.* v. *Memphis Light, Gas & Water Division,* 358 U.S. 103, 79 S.Ct. 194, 3 L.Ed. 2d 132 (1958), as well as the opinions of the United States Court of Appeals for the Tenth Circuit in *Phillips Petroleum Co.* v. *Federal Power Commission,* 227 F.2d 470 (1955) and *Kerr-McGee Oil Industries, Inc.* v. *Federal Power Commission,* 260 F.2d 602 (1958). We point out that in none of these cases was a question raised as to the validity, *on public policy grounds,* of contract clauses containing escalation features based on fortuitous events.

In *Memphis,* the Court held that a natural gas company could file a rate increase unilaterally if its customer had consented to such action. The court did not deal with the question of the reasonableness of such a rate increase under the Natural Gas Act; that was a matter for the Commission in the exercise of its regulatory jurisdiction under the Act. *Memphis* should be distinguished from a case involving a spiral escalation clause. In a *Memphis* situation, there is no reason to believe one way or another that the increase sought does not bear a reasonable relationship to costs. In the case of spiral escalation clauses, however, the very nature of the

clause indicates that the rate increase sought is not dependent upon an increase in costs but is merely dependent upon a fortuitous event—an increase in some other contract price.

As for the Tenth Circuit cases referred to by the Commission, the matter to be determined was the so-called "frozen" price under the contracts there involved as of

June 7, 1954, the date when regulation of producer prices by the Commission commenced. The court's resolution of the problem was based entirely upon principles of private contract law unfettered by any consideration of regulatory standards; it was the price *before regulation* that was at issue.

Thus there was no occasion in these cases to reach or to decide the question as to whether spiral escalation clauses are void as a matter of law. In the present proceedings, however, the Commission must consider spiral escalation clauses in terms of their effect on rates which are subject to the regulatory standards of the Natural Gas Act. This it has failed to do, addressing itself only to the question of the existence of customer consent to the pricing scheme contained in the spiral escalation clauses.

California contends that spiral escalations clauses are not geared to increases in costs and are therefore so derogatory of the public interest as to be void as a matter of law. In failing to so find, the Commission erred.

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CONCLUSION

On the grounds set forth herein petitioners, the People of the State of California and the Public Utilities Commission of the State of California, respectfully apply for rehearing in the instant proceedings and request that the order contained in Opinion No. 338, Opinion and Order

Determining Cost of Service and Terminating Proceedings, issued September 28, 1960, be stayed.

Respectfully submitted,

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Dated: October 26, 1960.

Application of the Eastern Seaboard Companies for Rehearing

I.

Position of Eastern Seaboard Companies [1]

It is the position of the Eastern Seaboard Companies, as set forth in this Application for Rehearing, that the Commission, in its Opinion No. 338 and Order issued herein on September 28, 1960, erred in failing to "fix the rates at which [Phillips' jurisdictional] . . . sales are made," as required by the opinion rendered in this proceeding by the United States Court of Appeals for the District of Columbia Circuit, *State of Wisconsin* v. *FPC*, 205 F. 2d 706, 712 (1953); affirmed 347 U.S. 672 (1954).

The Commission has a responsibility under the Natural Gas Act to determine and make proper findings as to the validity of Phillips' rates for all its jurisdictional gas sales. Moreover, and as pointed out above, the Courts have directed it to do so. In issuing Opinion No. 338, the Commission has taken the first and most difficult step toward accomplishing this goal by developing methods of ascertaining Phillips'

financial requirements. But the full responsibility imposed upon the Commission has not yet been met. Having found a cost of service applicable to Phillips' jurisdictional business and having the power to require submission of any necessary additional data, the Commission is under a clear duty to fix rates at which Phillips may make jurisdictional

[1] As used in this application, the term "Eastern Seaboard Companies" designates Long Island Lighting Company, Philadelphia Electric Company and The United Gas Improvement Company.

sales. Its failure to perform such duty is erroneous as a matter of law and constitutes a judicially-reversible abuse of discretion.[2]

The Commission should consolidate with G-1148 all of Phillips' pending Section 4(e) filings, should set such consolidated docket down for prompt hearing and should direct Phillips to submit a schedule of rates designed to recover its 1959 costs, determined in accordance with the practices established by the Commission in Opinion No. 338. The resolution of the issues posed by this proceeding, so sorely needed, can most expeditiously be achieved by such a course —not by ignoring current costs as well as current revenues and leaving the determination of the proper level of Phillips' rates to some unspecified time in the future.[3]

II.

The Commission Abused Its Discretion By Terminating These Proceedings Before Fixing Phillips' Rates For The Future.

The Commission's Opinion and Order herein contain no findings that Phillips' rates are "just and reasonable", that they are not "unduly discriminatory" or that they are "non-preferential". Rather, the Commission, finding that Phillips' 1954 revenues did not exceed its 1954 cost of service, terminated the Section 5(a) investigation and the consolidated Section 4(e) proceedings. This action constitutes an

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[2] In view of the Commission's use in this case of a cost-of-service basis for ascertaining jurisdictional revenues to which Phillips was entitled in the test year, the Eastern Seaboard Companies do not deal here with any of the Commission's comments concerning the cost-of-service method of regulation, appropriate allocation methods, alternative methods of producer regulation, or other theories not discussed in this application. Petitioners reserve the right however, to challenge any or all of these comments or conclusions in any proceeding where they have a direct bearing on rate levels.

[3] Involved are as many as 95 unconsolidated rate increase proceedings amounting to some $22 million annually. See Appendix C.

abuse of discretion in the circumstances of this case because (1) it conflicts with the basic policies of the Natural Gas Act as enunciated by the Supreme Court in *Hope, Colorado Interstate, Phillips* and CATCO, and (2) it ignores the Commission's responsibilities under

the Act as the Commission itself has so often recognized th m in terms of protecting consumers.

Section 4(a), 4(e) and 5(a) of the Act contemplates that the Commission will establish rates for natural gas companies which meet the standards prescribed by those sections. The Act, it is true, gives the Commission a certain amount of discretion in suspending rate increases or initiating rate investigations. This discretion is, however, bounded by the over-riding rate policies of the Act. The Commission cannot exercise its discretion in a way which conflicts with or negates basic Congressional policy. *Office Employees Int'l Union* v. *NLRB*, 353 U.S. 313, 316-320 (1957); *Schaffer Transportation Co.* v. *United States*, 355 U.S. 83, 88, 93-94 (1957).

Phillips' Section 5(a) investigation was reinstated in November, 1954, following the Supreme Court's *Phillips* decision, and a number of Section 4(e) rate increases were consolidated therewith for hearing. However, at various times since November, 1954, Phillips has filed not only additional, unconsolidated rate increases aggregating some $22 million in annual amount (which are effective subject to refund) but also a large number of new rate schedules, at rates far exceeding its unit cost, which have been certificated by the Commission without *any* inquiry into the level of the rates involved.

As a consequence, Phillips rate schedules now in effect generate revenues which are substantially greater than either its cost of service, as determined by the Commission in this proceeding, or its 1954 revenues. While Phillips

has a total of roughly 370 rate schedules now on file, Phillips' principal rate schedules number only about 130 (i.e., excluding casinghead-type and "de minimis" contracts). The filed rates as of September 28, 1960 included in 57 [4] of these principal rate schedules are subject to Section 4(e) proceedings, and to some extent to refund. Of the remaining 74, 70 [5] will not be subject to any rate "surveillance" if Phillips' Section 5(a) investigation is terminated. Of these 70 rates not subject to a Section 4 proceeding, 40 exceed the area rate standards for old gas announced by the Commission in its Statement of General Policy 61-1, which applies to gas sales certificated before September 28, 1960 and 6 exceed the price for new sales in that Statement (50 also exceed Phillips' unit cost of service) (Appendix A, *infra*).

[4] Four of these are involved in suspension proceedings due solely to change in tax reimbursement.

[5] Four contracts are unavailable.

A. Phillips' Current Revenues From "Old" Sales[6] Far Exceed Its Adjusted 1954 Cost of Service.

Appendix A hereto shows that, if Phillips' major sales in 1954 were made in the same volumes but were priced at the rates now in effect, its revenues would be increased by some $23 million a year and would total almost $62 million, or about $6.5 million more than Phillips' entire cost of service.[7] (This does not include the revenues from so-called *de minimis* and casinghead contracts, which would add about $1,463,000 a year (based on 1958 rate levels) nor does it include revenues from *new* sales i.e., sales made under post-1954 contracts, now being made by Phillips.) The current unit revenue from these "old" sales averages about 13.8 cents per Mcf, or substantially greater than Phillips' unit costs in 1954 (which the Commission found virtually unchanged as late as 1956, mimeo, p. 14). This very material increase results from the fact that the 1954 rates contained in 36 of Phillips' 48 principal rate schedules in effect during 1954 (as enumerated in Appendix A) are now superceded by substantially higher rates, the lawfulness of which was not passed upon by the Commission in Opinion No. 338. All such rate schedules in fact show an increase.

Additionally, Phillips' offer of settlement submitted in April 1960 and discussed in the Commission's Opinion, indicated that, without regard to new sales, Phillips would collect average revenues of about 14.4 cents per Mcf—even further above what the Commission has determined to be the company's unit costs, including a fair return.

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[6] I.e., contracts under which sales were being made in 1954 and are still being made in 1960.

[7] Since the Commission, for some unknown reason, has not required Phillips to file in 1960 the Form 301 report required by the Commission's Regulations, data relating to Phillips' 1959 revenues and costs, which would be revealed by that report are not available either to the Commission or the parties hereto.

These increases in Phillips' present levels of revenues for "old" sales have been ignored by the Commission, except for its promise to exercise "continuing surveillance" in pending non-consolidated Section 4(e) proceedings, and its announcement of area pricing standards which it might apply, in some unspecified way, at some indefinite time in the future (see dissenting opinion).

For example, one of the rate suspension proceedings terminated by the Commission Order, Docket No. G-4333, involves a sale to Transcontinental Gas Pipe Line Corporation (Transco) from the Tigre Lagoon Field, Vermilion Parish, Louisiana. The initial rate

for this sale was 8.5 cents per Mcf at 16.7 psia. This price escalated under a favored nation clause to 16 cents per Mcf, (at 15.025 psia) on February 25, 1955, plus 1 cent tax reimbursement. The rate now being collected for this sale, 23.55 cents per Mcf, has been in effect since July 9, 1959,[8] as a result of a favored nation filing arising out of the Commission's *Transco-Seaboard* order.[9] This 23.55 cent rate is being collected even though the validity of the triggering event—i.e., the new purchases by Transco—is still pending before the Commission on remand; and despite the Commission's pledge in its *Transco-Seaboard* order (Opinion No. 315, mimeo, p. 10) that petitioners would be protected against the triggering effect of that order:

> Second, UGI and the New York Commission contend that on the facts the examiner erred in concluding that there was no substantial evidence of harm to the public from the certification of these producers' sales at the prices proposed. They argue that triggering would increase the price of gas purchased by Transco and ulti-

[8] Pursuant to an order entered July 17, 1959 in Docket No. G-17[illegible].

[9] In the Matter of *Transcontinental Gas Pipe Line Corp., et al.*, Opinion No. 315, Issued September 4, 1958; 20 FPC 264.

mately the consumer by as much as $5,000,000 a year. The fact is, however, that before any such "triggered" increases could be passed along, filings for increased rates would have to be made by the producers and these would be subject to our scrutiny and control under the rate suspension provisions of Section 4 of the Act.[10]

The Commission has an obligation not merely to suspend Phillips' presumptively unlawful rate increases, but also promptly to determine the lawfulness of all of Phillips' untested rates under Section 5(a) and 4(e) of the Act.

Accordingly, it is required to determine the lawfulness of the interim Tigre Lagoon 17¢ per Mcf rate in conjunction with all of Phillips' other rates, which it cannot do merely by terminating the existing Section 5(a) proceeding. Furthermore, the Commission abused its discretion by failing to "scrutinize and control" the Tigre Lagoon rate increase to 23.55 per Mcf, as it assured the consumer it would do. It similarly erred with respect to the approximately 94 other pending but unconsolidated rate increases (Opinion No. 338, mimeo, p. 50) with refund periods running from various dates since April, 1957 (Appendix C, *infra*).[11]

[10] Note 9, *supra* at 274.

[11] "The Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible." Natural Gas Act, § 4(e), 15 USC § 717c(e) (1958).

B. Phillips' Revenues Under "New" Sales Are Also Substantially in Excess of Costs.

Phillips' rate schedules for "new" sales [12] will generate revenues of about $25 million annually, averaging about 19 cents per Mcf, or more than half again as much as the Commission's determination of Phillips' average unit costs in 1954.

A substantial number (approximately 55)[13] of these "new" sales are currently being made under rates no part of which are subject to refund for any period and which are among the highest filed rates now in effect. According to the billing data submitted in the rate schedules, even these new rates alone will generate average unit revenues of about 18¢ per Mcf, far above *Phillips'* cost of service in its adjusted test year. All but 16 of these sales exceed the Commission's lower area rate standard for gas sales, and 6 exceed the Commission's standard for initial sales. (Appendix B).

Thus, there can be very little doubt that Phillips' current revenues substantially exceed its cost of service. Despite this strong evidence that Phillips' current rates are unlawful, the Commission has terminated its Section 5(a) investigation.

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[12] I.e. rate schedules shown in Appendix B, starting at No. 273 and extending through rate schedule 371, not included in G-1148 exhibits or considered there. This Appendix also lists the Commission's announced area rate standards, for old and new sales, shows indicated revenues, the docket numbers of Section 4 proceedings involving such sales and the current status of the sales under Section 7.

[13] Complete figures are unobtainable, since it is impossible to determine in some cases from the Commission's public records the present certified status of Phillip's sales. Most of these initial sales were certificated by the Commission before the Supreme Court's CATCO decision at a time when the Commission was under a misapprehension as to the "most careful scrutiny" of initial prices required in producer certificate cases. In several cases, certificates were issued after uncontested hearings.

III.

There Is No Record Support For The Commission's Assumption That General Industry Cost Increases Justify Dismissal Of Phillips' Section 5(a) Proceeding.

The Commission's sole attempt to justify its failure to complete the "nigh interminable" Phillips' rates investigation by determining "just and reasonable" rates for its current and future sales, is found in its comment that Phillips' higher current rates are "probably" reasonable through 1958 because its costs have increased. Thus, the Commission inferentially recognizes that Phillips' revenues in all probability exceed its costs at least in 1959 and later years. In any case, there is absolutely no evidence of record establishing that Phillips'

cost have increased from 1954 through 1958, and the Commission has not used the methods readily available for ascertaining this fact.

The Commission's failure to do so is particularly unfortunate, since Phillips' higher rates do not necessarily reflect cost increases but rather are the result of fixed price escalations, or favored nation, spiral, or other formulative price redeterminations. Accordingly, while the Commission may properly infer higher "prices of gas in the field" from the higher rates, it may not legitimately infer higher costs.

The Commission suggests that the consumer will not be injured by the termination of this proceeding because Phillips' higher initial rates are still subject (prospectively only) to the Commission's proposed area price program (mimeo., p. 51).[14] But the Commission program, as its

[14] The Commission's argument (mimeo., p. 51) that Phillips' current *increased* rates involved in Section 4(e) proceedings are still subject to refund overlooks the fact that the Commission later in its Opinion (mimeo., p. 53) states that it intends to terminate all of Phillips' suspension proceedings involving rates filed prior to 1959.

Opinion recognizes, is still in embryo, so that when, if ever, the consumer will obtain even mere *prospective* relief from Phillips' new higher rates is problematical.

The Commission has told the Federal courts repeatedly in recent cases involving its rate procedures that Section 5(a) proceedings, such as that in Phillips, would provide more than adequate consumer protection against excessive initial producer prices.

See, as examples, briefs for the Federal Power Commission in:

Atlantic Refining Co. v. *P.S.C. of New York,* Sup. Ct., October Term 1958, No. 518, pp. 100-101.

Oklahoma Natural Gas Co. v. *FPC,* CADC, No. 13783, pp. 15, 28.

The United Gas Improvement Co. v. *FPC,* Nos. 12797 and 12805, pp. 49-59.

The United Gas Improvement Co. v. *FPC,* CA 9, No. 16692, pp. 28-29.

These repeated representations by the Commission to the Federal courts make it difficult to understand its termination of an *existing* Section 5(a) proceeding in the face of *existing* untested initial prices at levels far exceeding the prices approved in this proceeding. Certainly, the Commission's purported awareness, *dehors* this record,

that producer costs have in general increased some indefinite amount from 1954 through 1958 does not support the lawfulness of the particular high initial prices being collected by Phillips in 1959. Especially is this so in view of the fact that the Commission's Opinion, as stated, appears to recognize that Phillips' 1959-1960 revenues *exceed* cost of service.

Hence, assumed general cost increases cannot justify delaying indefinitely the test of Phillips' high initial prices under Section 5(a) of the Act. As the Supreme Court emphasized in CATCO (360 U.S. at 389-390):

> . . . the delay incident to determination in § 5 proceedings through which initial certificated rates are reviewable appears nigh interminable. Although *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, 98 L.ed. 1035, 74 S.Ct. 794, was decided in 1954, cases instituted under § 5 are still in the investigative stage. This long delay, without the protection of refund, as is possible in a § 4 proceeding, would provide a windfall for the natural gas company with a consequent squall for the consumers. *This the Congress did not intend.* [Emphasis supplied]

IV.

The Commission Should Direct Phillips To Submit Revised Rate Schedules Which Will Recover Its 1959 Costs, Determined In Accordance With Opinion 338.

The data assembled in the appendices to this petition, while admittedly and unavoidably incomplete, demonstrate that the Commission will abuse its discretion if it terminates this proceeding without fixing Phillips' just and reasonable rates, so as to give Phillips' customers in *this* proceeding the protection contemplated by Sections 4(e) and 5(a) of the Natural Gas Act. The Commission should grant rehearing, consolidate herein all of Phillips' Section 4(e) proceedings and direct Phillips to submit a 1959 cost of service determination based on the practices and methods set forth in Opinion No. 338, as well as revised rates schedules designed to return its current costs. Consideration of these rate schedules and cost of service in a single hearing should take substantially less time than hearings on the unconsolidated Section 4(e)'s. In preparing new rate schedules, Phillips would of course have available for guidance the Commission's Policy Statement 61-1. This procedure

would best serve the purpose of the Commission's proposal for settlement of Phillips' outstanding Section 4(e) proceedings (mimeo, p. 53).

The Eastern Seaboard Companies would welcome, and will make every effort to expedite, complete disposition or settlement of all of Phillips' pending rate controversies, so that this long continued proceeding can be concluded as rapidly as possible.

Respectfully submitted,

LONG ISLAND LIGHTING COMPANY
PHILADELPHIA ELECTRIC COMPANY
THE UNITED GAS IMPROVEMENT COMPANY

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October 28, 1960.

32832

DISTRICT OF COLUMBIA)
CITY OF WASHINGTON) ss.

J. David Mann, Jr., being duly sworn according to law, deposes and says that he is Attorney for the Eastern Seaboard Companies, Applicants herein; that he is authorized to make this affidavit; that he has read the foregoing Application for Rehearing; that he is familiar with the facts set forth therein, and that such facts are true and correct to the best of his knowledge and belief.

J. DAVID MANN, JR.

Subscribed and sworn to before me this 28th day of October, 1960.

SHELVA JEAN FRENZEL
Notary Public

My Commission Expires:
January 31, 1965

[SEAL]

COMPARISON OF ANNUAL REVENUES BASED ON 1954 VOLUMES FOR PHILLIPS' MAJOR SALES UNDER 1954 RATES AND RATES ON FILE AS OF SEPTEMBER 28, 1960, EXCLUDING REVENUES FROM NEW SALES, CASINGHEAD AND "DE MINIMIS" CONTRACTS*

Rate Schedule Number	Purchaser	County	State	Area Designation	F.P.C. Area Price New Gas	F.P.C. Area Price Old Gas	1954 Volume (Mcf)	1954 Price per Mcf	Revenue at 1954 Price
					(14.65 Psia)		(14.65 Psia)		
2-A	Texas Eastern Trans. Corp.	Orange	T	R. R. #3	18.0¢	14.0¢	2,477,038	12.8116¢	$ 317,348.97
3	Tennessee Gas Trans. Co.	Hidalgo	T	R. R. #4	18.0	14.0	165,333	9.8172	16,231.02
4	Michigan-Wisconsin PL Co.	Sherman, Hansford Texas	T O	R. R. #10 Panhandle	17.0	11.0	126,671,655	8.7492[1]	11,082,716.85
5	Panhandle Eastern PL Co.								
	Hansford Plant	Hansford, Moore	T	R. R. #10	17.0	11.0	12,476,091	4.5968	573,494.77
	Hansford Plant	Texas	O	Panhandle	17.0	11.0	19,837,564	9.8301	1,950,054.91
	Sneed Plant	Moore	T	R. R. #10	17.0	11.0	20,218,051	4.9800	1,006,856.47
7	El Paso Natural Gas Co.	Ector	T	R. R. #8	16.0	11.0	122,560	7.0012	8,580.68
8	El Paso Natural Gas Co.	Crane	T	R. R. #8	16.0	11.0	341,932	7.0411	24,075.77
9	El Paso Natural Gas Co.	Crane	T	R. R. #8	16.0	11.0	7,013,313	5.8187	408,086.37
10	El Paso Natural Gas Co.	Winkler	T	R. R. #8	16.0	11.0	2,054,887	9.0004	184,948.82
13	United Gas Pipe Line Co.	Panola	T	R. R. #6	15.0	14.0	3,047,243	8.5221	259,689.09
18	Permian Basin Pipe Line Co.	Midland, Upton, Pecos	T	R.R.#8,7-c	16.0	11.0	32,715,906	9.4347[1]	3,086,660.40
19	Consolidated Gas Utilities	Gray	T	R. R. #10	17.0	11.0	12,155,597	11.1118	1,350,707.03
20	Tennessee Gas Trans. Co.	Nueces	T	R. R. #4	18.0	14.0	275,340	9.4435	26,001.69
21	Colo. Interstate Gas Co.	Hutchinson	T	R. R. #10	17.0	11.0	14,565,740	15.0000	2,184,861.00
23	Texas Gas Trans. Corp.	Panola	T	R. R. #6	15.0	14.0	809,060	9.6220	77,847.51
24	Northern Natural Gas Co.	Moore	T	R. R. #10	17.0	11.0	18,541,588	10.8693	2,015,332.02
27	Texas Ill. Nat. Gas PL Co.	Brazoria	T	R. R. #3	18.0	14.0	10,220,000	9.5506	976,069.89
31	Arkansas Louisiana Gas Co.	Harrison	T	R. R. #6	15.0	14.0			
		Caddo	L	No. La.	16.6[2]	13.7[2]	714,458	9.1439	65,329.10
32	El Paso Natural Gas Co.								
	Goldsmith Plant	Ector	T	R. R. #8	16.0	11.0	25,600,659	7.0002	1,792,563.17
	Eunice Plant	Lea	NM	P.B.	16.0	11.0	12,433,435	7.0000	870,340.45
	Fullerton Plant	Andrews	T	R. R. #8	16.0	11.0	5,889,576	7.0015	412,356.08
	Dumas Plant	Carson	T	R. R. #10	17.0	11.0	38,780,996	9.3294	3,618,027.37
33	El Paso Natural Gas Co.	Ector	T	R. R. #8	16.0	11.0	8,577,295	7.0021	600,591.75
39	Tennessee Gas Trans. Co.	Matagorda	T	R. R. #3	18.0	14.0	167,488	9.2349	15,467.36
41	Tex.-Ill. Nat. Gas PL Co.	Brazoria	T	R. R. #3	18.0	14.0	6,503,518	15.1339	984,237.57
42	Texas Gas Corp.	Jefferson	T	R. R. #3	18.0	14.0	150,976	7.9218	11,959.95
47	El Paso Natural Gas Co.	Upton	T	R.R. #7-c	16.0	11.0	1,292	9.9605	128.69
48	Arkansas Louisiana Gas Co.	Bossier, Webster	L	No. La.	16.6[2]	13.7[2]	20,839	9.6247	2,005.70
52[4]	Panhandle Eastern PL Co.	Moore	T	R. R. #10	17.0	11.0	321,406	1.3568	4,360.86
59	Permian Basin Pipe Line Co.	Lea	NM	P.B.	16.0	11.0	408,304	9.8425	40,187.33
51[4]	Panhandle Eastern PL Co.	Moore	T	R. R. #10	17.0	11.0	7,598,048	2.8742	218,380.44
64	El Paso Natural Gas Co.	Lea	NM	P.B.	16.0	11.0	13,476,859	7.0000	943,380.13
65	El Paso Natural Gas Co.	Lea	NM	P.B.	16.0	11.0	505,830	9.5635	48,374.92

COMPARISON OF ANNUAL REVENUES BASED ON 1954 VOLUMES FOR PHILLIPS' MAJOR SALES UNDER 1954 RATES AND RATES ON FILE AS OF SEPTEMBER 28, 1960, EXCLUDING REVENUES FROM NEW SALES, CASINGHEAD AND "DE MINIMIS" CONTRACTS*

County	State	Area Designation	F.P.C. Area Price New Gas (14.65 Psia)	F.P.C. Area Price Old Gas (14.65 Psia)	1954 Volume (Mcf) (14.65 Psia)	1954 Price per Mcf	Revenue at 1954 Price	Filed Rate as of 9/28/60 (14.65 Psia)	Revenue at 1960 Filed Rate	Increase in Revenue 1954-1960
Orange	T	R. R. #3	18.0¢	14.0¢	2,477,038	12.8116¢	$ 317,348.97	14.8000¢	$ 366,601.62	$ 49,252.65
Hidalgo	T	R. R. #4	18.0	14.0	165,333	9.8172	16,231.02	17.2435	28,509.20	12,278.18
Sherman,Hansford Texas	T O	R. R. #10 Panhandle	17.0	11.0	126,671,655	8.7492[1]	11,082,716.85	12.7295[2]	16,124,668.32	5,041,951.47
Hansford,Moore	T	R. R. #10	17.0	11.0	12,476,091	4.5968	573,494.77	13.0000	1,621,891.83	1,048,397.06
Texas	O	Panhandle	17.0	11.0	19,837,564	9.8301	1,950,054.91	13.0000	2,578,883.32	628,828.41
Moore	T	R. R. #10	17.0	11.0	20,218,051	4.9800	1,006,856.47	13.0000	2,628,346.63	1,621,490.16
Ector	T	R. R. #8	16.0	11.0	122,560	7.0012	8,580.68	17.1286	20,992.81	12,412.13
Crane	T	R. R. #8	16.0	11.0	341,932	7.0411	24,075.77	13.3632[3]	45,693.06	21,617.29
Crane	T	R. R. #8	16.0	11.0	7,013,313	5.8187	408,086.37	13.3632	937,203.04	529,116.67
Winkler	T	R. R. #8	16.0	11.0	2,054,887	9.0004	184,948.82	17.1286	351,973.37	167,024.55
Panola	T	R. R. #6	15.0	14.0	3,047,243	8.5221	259,689.09	9.5000	289,488.08	29,798.99
Midland, Upton, Pecos	T	R.R.#8,7-c	16.0	11.0	32,715,906	9.4347[1]	3,086,660.40	11.1056	3,633,297.66	546,637.26
Gray	T	R. R. #10	17.0	11.0	12,155,597	11.1118	1,350,707.03	14.1792	1,723,566.41	372,859.38
Nueces	T	R. R. #4	18.0	14.0	275,340	9.4435	26,001.69	17.0242	46,874.43	20,872.74
Hutchinson	T	R. R. #10	17.0	11.0	14,565,740	15.0000	2,184,861.00	17.1632	2,499,947.09	315,086.09
Panola	T	R. R. #6	15.0	14.0	809,060	9.6220	77,847.51	10.5000	84,951.30	7,103.79
Moore	T	R. R. #10	17.0	11.0	18,541,588	10.8693	2,015,332.02	14.4443	2,678,202.60	662,870.58
Brazoria	T	R. R. #3	18.0	14.0	10,220,000	9.5506	976,069.89	10.8951	1,113,479.22	137,409.33
Harrison Caddo	T L	R. R. #6 No. La.	15.0 16.6[2]	14.0 13.7[2]	714,458	9.1439	65,329.10	11.5055	82,201.97	16,872.87
Ector	T	R. R. #8	16.0	11.0	25,600,659	7.0002	1,792,563.17	13.6155	3,485,657.73	1,693,094.56
Lea	NM	P.B.	16.0	11.0	12,433,435	7.0000	870,340.45	13.5330	1,682,616.76	812,276.31
Andrews	T	R. R. #8	16.0	11.0	5,889,576	7.0015	412,356.08	13.6155	801,895.22	389,539.14
Carson	T	R. R. #10	17.0	11.0	38,780,996	9.3294	3,618,027.37	19.7633	7,664,404.58	4,046,377.21
Ector	T	R. R. #8	16.0	11.0	8,577,295	7.0021	600,591.75	13.6155	1,167,841.60	567,249.85
Matagorda	T	R. R. #3	18.0	14.0	167,488	9.2349	15,467.36	16.1695	27,081.97	11,614.61
Brazoria	T	R. R. #3	18.0	14.0	6,503,518	15.1339	984,237.57	15.6000	1,014,548.81	30,311.24
Jefferson	T	R. R. #3	18.0	14.0	150,976	7.9218	11,959.95	11.0000[2]	16,607.36	4,647.41
Upton	T	R.R. #7-c	16.0	11.0	1,292	9.9605	128.69	15.7092	202.96	74.27
Bossier,Webster	L	No. La.	16.6[2]	13.7[2]	20,839	9.6247	2,005.70	12.2407	2,550.84	545.14
Moore	T	R. R. #10	17.0	11.0	321,406	1.3568	4,360.86	10.0000	32,140.60	27,779.74
Lea	NM	P.B.	16.0	11.0	408,304	9.8425	40,187.33	10.5000	42,871.92	2,684.59
Moore	T	R. R. #10	17.0	11.0	7,598,048	2.8742	218,380.44	10.0000	759,804.80	541,424.36
Lea	NM	P.B.	16.0	11.0	13,476,859	7.0000	943,380.13	13.5330	1,823,823.33	880,443.20
Lea	NM	P.B.	16.0	11.0	505,830	9.5635	48,374.92	15.5598	78,706.14	30,331.22

Rate Schedule Number	Purchaser	County	State	Area Designation	F.P.C. Ar New Gas
					(14.65
66	El Paso Natural Gas Co.	Lea	NM	P.B.	16.0¢
68	Cities Service Gas Co.	Oklahoma	O	Other	15.0
69	Cities Service Gas Co.	Oklahoma	O	Other	15.0
83	Shamrock Oil & Gas Corp.	Moore	T	R. R. #10	17.0
140	Arkansas Louisiana Gas Co.	Cass	T	R. R. #5	15.0
143[4]	Panhandle Eastern PL Co.	Moore	T	R. R. #10	17.0
148	C. V. Lyman	Winkler	T	R. R. #8	16.0
150	Consolidated Gas Utilities	Grady	O	Carter Knox	16.8
175	Southern Natural Gas Co.	DeSoto	L	No. La.	16.6[2]
202	Texas Northern Gas Corp.	Acadia	L	So. La.	20.96[2]
209	Tennessee Gas Trans. Co.	Colorado,Wharton	T	R. R. #3	18.0
218	Tennessee Gas Trans. Co.	Acadia	L	So. La.	20.96[2]
219	Southern Natural Gas Co.	Plaquemines, St. Bernard	L	So. La.	20.96[2]
220	Transcontinental Gas PL Co.	Vermilion	L	So. La.	20.96[2]
231	Tennessee Gas Trans. Co.	Wharton	T	R. R. #3	18.0
239	Mississippi River Fuel Corp.	Lincoln	L	No. La.	16.6[2]
243	El Paso Natural Gas Co.				
	Lee Plant	Lea	NM	P.B.	16.0
	Hobbs Plant	Lea	NM	P.B.	16.0
262[5]	Northern Natural Gas Co.	Gray	T	R. R. #10	17.0
270[4]	Panhandle Eastern PL Co.	Moore	T	R. R. #10	17.0
J.E. 1[7]	Cities Service Gas Co.	Oklahoma	O	Other	15.0
J.E. 2[7]	Cities Service Gas Co.	Oklahoma	O	Other	15.0
		Total			

State Code:
T - Texas
O - Oklahoma
L - Louisiana
NM - New Mexico

1/ Weighted average price.
2/ Excludes tax.
3/ Rate Schedule #8 superseded by #9.
4/ Rate Schedule #356 supersedes #52, #61, #143, #270.
5/ Rate Schedule #262 supersedes #26 and #28.
6/ Price shown on Exhibit 223 is incorrectly shown as 9.9644.
7/ West Edmond Oil Co.

*Contracts which have terminated since 1954 are not included.

1954 Data are from Exhibits 223 and 289 In the Matter of Phillips Petroleum Company, from the rate schedules, supplements and billing statements on file with the Federal Statement of General Policy No. 61-1, Issued September 28, 1960; First Amendment to October 25, 1960.

. Area Price

Old Gas	1954 Volume (Mcf)	1954 Price per Mcf	Revenue at 1954 Price	Filed Rate as of 9/28/60
.65 Psia)	(14.65 Psia)			(14.65 Psia)
11.0¢	251,808	9.98164¢	$ 25,134.42	17.0436
11.0	6,477,720	6.7165[1]	435,074.12	7.5930
11.0	1,282,711	6.7165	86,152.90	7.6302
11.0	226,468	6.5000	14,720.39	8.5000
14.0	255,633	6.5793[6]	16,818.86	7.4566
11.0	381,273	2.4408	9,306.09	10.0000
11.0	180,697	6.0000	10,841.79	7.0000
11.0	185,466	10.0000	18,546.51	13.0000
13.7[2]	1,370,081	11.1605	152,908.18	14.1240
13.7[2]	301,220	8.7724	26,424.33	20.2916
14.0	192,035	15.4111	29,594.70	15.9502
13.7[2]	331,990	7.7544	25,743.81	22.2635
13.7[2]	1,097,355	11.8749	130,309.97	23.0841
13.7[2]	513,047	9.3247	47,839.90	22.9622
14.0	243,943	13.2883	32,415.96	15.9502
13.7[2]	470,339	10.8241	50,909.77	12.9222
11.0	3,342,639	6.6808	223,314.05	14.0343
11.0	5,820,272	5.0479	293,801.88	13.5330
11.0	17,914,056	10.5132[1]	1,883,347.39	18.9300
11.0	864,127	5.4490	47,086.31	10.0000
11.0	148,459	6.7200	9,976.44	7.6302
11.0	410,074	6.7200	27,556.97	7.5930
	447,121,290		$38,775,078.87	

pany, Docket Nos. G-1148, et al.; 1960 filed rates are
leral Power Commission. Federal Power Commission,
to Statement of General Policy No. 61-1, Issued

County	State	Area Designation	F.P.C. Area Price New Gas (14.65 Psia)	F.P.C. Area Price Old Gas	1954 Volume (Mcf) (14.65 Psia)	1954 Price per Mcf	Revenue at 1954 Price	Filed Rate as of 9/28/60 (14.65 Psia)	Revenue at 1960 Filed Rate	Increase in Revenue 1954-1960
Lea	NM	P.B.	16.0¢	11.0¢	251,808	9.9816¢	$ 25,134.42	17.0436	$ 42,917.15	$ 17,782.73
Oklahoma	O	Other	15.0	11.0	6,477,720	6.7165[1]	435,074.12	7.5930	491,853.28	56,779.16
Oklahoma	O	Other	15.0	11.0	1,282,711	6.7165	86,152.90	7.6302	97,873.41	11,720.51
Moore	T	R. R. #10	17.0	11.0	226,468	6.5000	14,720.39	8.5000	19,249.78	4,529.39
Cass	T	R. R. #6	15.0	14.0	255,633	6.5793[6]	16,818.86	7.4566	19,061.53	2,242.67
Moore	T	R. R. #10	17.0	11.0	381,273	2.4408	9,306.09	10.0000	38,127.30	28,821.21
Winkler	T	R. R. #8	16.0	11.0	180,697	6.0000	10,841.79	7.0000	12,648.79	1,807.00
Grady	O	Carter Knox	16.8	11.0	185,466	10.0000	18,546.51	13.0000	24,110.58	5,564.07
DeSoto	L	No. La.	16.6[2]	13.7[2]	1,370,081	11.1605	152,908.18	14.1240	193,510.24	40,602.06
Acadia	L	So. La.	20.96[2]	13.7[2]	301,220	8.7724	26,424.33	20.2916	61,122.36	34,698.03
Colorado,Wharton	T	R. R. #3	18.0	14.0	192,035	15.4111	29,594.70	15.9502	30,629.97	1,035.27
Acadia	L	So. La.	20.96[2]	13.7[2]	331,990	7.7544	25,743.81	22.2635	73,912.59	48,168.78
Plaquemines, St. Bernard	L	So. La.	20.96[2]	13.7[2]	1,097,355	11.8749	130,309.97	23.0841	253,314.53	123,004.56
Vermilion	L	So. La.	20.96[2]	13.7[2]	513,047	9.3247	47,839.90	22.9622	117,806.88	69,966.98
Wharton	T	R. R. #3	18.0	14.0	243,943	13.2883	32,415.96	15.9502	38,909.40	6,493.44
Lincoln	L	No. La.	16.6[2]	13.7[2]	470,339	10.8241	50,909.77	12.9222	60,778.15	9,868.38
Lea	NM	P.B.	16.0	11.0	3,342,639	6.6808	223,314.05	14.0343	469,115.99	245,801.94
Lea	NM	P.B.	16.0	11.0	5,820,272	5.0479	293,801.88	13.5330	787,657.41	493,855.53
Gray	T	R. R. #10	17.0	11.0	17,914,056	10.5132[1]	1,883,347.39	18.9300	3,391,130.80	1,507,783.41
Moore	T	R. R. #10	17.0	11.0	864,127	5.4490	47,086.31	10.0000	86,412.70	39,326.39
Oklahoma	O	Other	15.0	11.0	148,459	6.7200	9,976.44	7.6302	11,327.72	1,351.28
Oklahoma	O	Other	15.0	11.0	410,074	6.7200	27,556.97	7.5930	31,136.92	3,579.95
Total					447,121,290		$38,775,078.87		$61,810,134.06	$23,035,055.19

#9.
52, #61, #143, #270.
26 and #28.
ncorrectly shown as 9.9644.

nce 1954 are not included.

289 In the Matter of Phillips Petroleum Company, Docket Nos. G-1148, et al.; 1960 filed rates are
s and billing statements on file with the Federal Power Commission. Federal Power Commission,
1, Issued September 28, 1960; First Amendment to Statement of General Policy No. 61-1, Issued

Comparison of Prices Under "New" Rate Schedules,* Not Included in Docket No. G-1148 et al., With Area Rate Standards Set Forth in Statement of General Policy No. 61-1 and First Amendment Thereto

Rate Schedule Number	Purchaser	County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60
273	United Fuel Gas Company	Vermilion	Louisiana	So. La.	20.96¢ 1/	13.70¢ 1/	22.3099¢
274	El Paso Natural Gas Company	Lea	New Mexico	Permian Basin	16.00	11.00	15.5598
275	Wilcox Trend Gathering System, Inc.	Live Oak	Texas	R.R. #2	18.00	14.00	11.8254
276	Louisiana Nevada Transit Company	Webster	Louisiana	No. La.	16.60 1/	13.70 1/	11.7005
277	Colorado Interstate Gas Company	Haskell	Kansas	Kansas	16.00	11.00	12.0900
278	American Louisiana Pipe Line Company	Acadia, St. Landry	Louisiana	So. La.	20.96 1/	13.70 1/	20.9634
279	Pacific Northwest Pipe Line Corp.	Sublette	Wyoming	Wyoming	15.00	12.70	19.0133
281	Texas Eastern Transmission Corp.	Live Oak	Texas	R.R. #2	18.00	14.00	11.8254
282	Warren Petroleum Corp.	Wheeler	Texas	R.R. #10	17.00	11.00	5.2500
286	Texas Eastern Transmission Corp.	Gregg	Texas	R.R. #6	15.00	14.00	14.8000
288	Kerr-McGee Oil Industries, Inc.	Carson	Texas	R.R. #10	17.00	11.00	11.3057
289	Kansas-Nebraska Natural Gas Co., Inc.	Texas	Oklahoma	Panhandle	17.00	11.00	16.0000 1/
290	Panhandle Eastern Pipeline Co.	Texas	Oklahoma	Panhandle	17.00	11.00	16.0000
291	Pioneer Gathering System, Inc.	Val Verde	Texas	R.R. #1	15.00	14.00	10.7500
292	Natural Gas Pipeline Co. of America	Beaver	Oklahoma	Panhandle	17.00	11.00	16.6000
294	Northern Natural Gas Company	Hansford	Texas	R.R. #10	17.00	11.00	16.5000
295	United Gas Pipe Line Company	Terrebonne	Louisiana	So. La.	20.96 1/	13.70 1/	19.5008 1/
296	Panhandle Eastern Pipeline Company	Meade	Kansas	Kansas	16.00	11.00	15.0000
297	Cities Service Gas Company	Woods	Oklahoma	Other	15.00	11.00	12.0000
298	Natural Gas Pipeline Co. of America	Texas	Oklahoma	Panhandle	17.00	11.00	16.8000
299	Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96 1/	13.70 1/	23.0841
300	Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96 1/	13.70 1/	23.0841
301	Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96 1/	13.70 1/	23.0841
302	Kansas-Nebraska Natural Gas Co., Inc.	Texas	Oklahoma	Panhandle	17.00	11.00	16.6000
303	Pacific Northwest Pipeline Corp.	Rio Blanco	Colorado	Colorado	14.60	12.70	14.6256
304	Arkansas Louisiana Gas Company	Claiborne	Louisiana	No. La.	16.60 1/	13.70 1/	12.2407
306	Permian Basin Pipeline Company	Winkler	Texas	R.R. #8	16.00	11.00	16.0000
307	Natural Gas Pipeline Co. of America	Texas	Oklahoma	Panhandle	17.00	11.00	16.6000
309 2/	El Paso Natural Gas Co.; Hunt Oil Co.	Upton	Texas	R.R. #7-C	16.00	11.00	13.6822
310 2/	Montana-Dakota Utilities Company	Park	Wyoming	Wyoming	15.00	12.70	7.8003
311	Consolidated Gas Utilities Corp.	Grady	Oklahoma	Other	15.00	11.00	11.0000
312	Texas Gas Gathering Corp.	Tensas	Louisiana	No. La.	16.60 1/	13.70 1/	14.1381
313	Panhandle Eastern Pipeline Company	Seward	Kansas	Kansas	16.00	11.00	15.0000
314	Panhandle Eastern Pipeline Company	Hansford	Texas	R.R. #10	17.00	11.00	16.0000
315	El Paso Natural Gas Company	Reagan	Texas	R.R. #7-C	16.00	11.00	17.2295
317	Trunkline Gas Company	Brazoria	Texas	R.R. #3	18.00	14.00	20.0000
318	Trunkline Gas Company	Galveston	Texas	R.R. #3	18.00	14.00	20.0000
319	United Gas Pipe Line Company	Panola	Texas	R.R. #6	15.00	14.00	13.0000
321	Cities Service Gas Company	Barber	Kansas	Kansas	16.00	11.00	13.0000
322	United Gas Pipe Line Company	San Patricio, Nueces	Texas	R.R. #4	18.00	14.00	14.8000
323	Lone Star Gas Company	Carter	Oklahoma	Other	15.00	11.00	13.2000 3/

Comparison of Prices Under "New" Rate Schedules,* Not Included in Docket No. G-1148 et al., With Area Rate Standards Set Forth in Statement of General Policy No. 61-1 and First Amendment Thereto

Purchaser	County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60	Latest Indicated Annual Volume	Annual Revenue at 1960 Filed Rate	Docket Numbers § 4e Proceedings	Docket Numbers Certific Proceedin
United Fuel Gas Company	Vermilion	Louisiana	So. La.	20.96¢/	13.70¢/	22.3099¢	23,890,032	$5,329,842	G-20013	
El Paso Natural Gas Company	Lea	New Mexico	Permian Basin	16.00	11.00	15.5598	401,543	62,479	G-20403	
Wilcox Trend Gathering System, Inc.	Live Oak	Texas	R.R. #2	18.00	14.00	11.8254	32,546	3,849		
Louisiana Nevada Transit Company	Webster	Louisiana	No. La.	16.60¢/	13.70¢/	11.7005	713,816	83,520		
Colorado Interstate Gas Company	Haskell	Kansas	Kansas	16.00	11.00	12.0900	120,816	14,607		
American Louisiana Pipe Line Company	Acadia, St. Landry	Louisiana	So. La.	20.96¢/	13.70¢/	20.9634	1,282,827	268,924	G-15597	
Pacific Northwest Pipe Line Corp.	Sublette	Wyoming	Wyoming	15.00	12.70	19.0133	1,015,536	193,087	G-16713	
Texas Eastern Transmission Corp.	Live Oak	Texas	R.R. #2	18.00	14.00	11.8254	29,200	3,453		
Warren Petroleum Corp.	Wheeler	Texas	R.R. #10	17.00	11.00	5.2500	72,000	3,780		
Texas Eastern Transmission Corp.	Gregg	Texas	R.R. #6	15.00	14.00	14.8000	15,344	2,271	G-19581	
Kerr-McGee Oil Industries, Inc.	Carson	Texas	R.R. #10	17.00	11.00	11.3057	5,920	669	RI60-475	
Kansas-Nebraska Natural Gas Co., Inc.	Texas	Oklahoma	Panhandle	17.00	11.00	16.0000[1]	260,400	41,664		
Panhandle Eastern Pipeline Co.	Texas	Oklahoma	Panhandle	17.00	11.00	16.0000	69,876	11,180		
Pioneer Gathering System, Inc.	Val Verde	Texas	R.R. #1	15.00	14.00	10.7500	4,464,000	479,880		
Natural Gas Pipeline Co. of America	Beaver	Oklahoma	Panhandle	17.00	11.00	16.6000	29,964	4,974	G-18272	
Northern Natural Gas Company	Hansford	Texas	R.R. #10	17.00	11.00	16.5000	1,860,000	306,900		
United Gas Pipe Line Company	Terrebonne	Louisiana	So. La.	20.96¢/	13.70¢/	19.5008[1]	638,562	124,525	G-15752	
Panhandle Eastern Pipeline Company	Meade	Kansas	Kansas	16.00	11.00	15.0000	1,080,000	162,000		
Cities Service Gas Company	Woods	Oklahoma	Other	15.00	11.00	12.0000	99,996	12,000		
Natural Gas Pipeline Co. of America	Texas	Oklahoma	Panhandle	17.00	11.00	16.8000	125,504	21.085	G-20339	
Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96¢/	13.70¢/	23.0841	2,335,525	539,135	G-17156	
Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96¢/	13.70¢/	23.0841	2,758,942	636,877	G-17156	
Southern Natural Gas Company	Plaquemines	Louisiana	So. La.	20.96¢/	13.70¢/	23.0841	1,738,780	401,382	G-17267	
Kansas-Nebraska Natural Gas Co., Inc.	Texas	Oklahoma	Panhandle	17.00	11.00	16.6000	7,299	1,212	RI61-64	
Pacific Northwest Pipeline Corp.	Rio Blanco	Colorado	Colorado	14.60	12.70	14.6256	572,283	83,700		
Arkansas Louisiana Gas Company	Claiborne	Louisiana	No. La.	16.60¢/	13.70¢/	12.2407	70,346	8,611	G-15721	
Permian Basin Pipeline Company	Winkler	Texas	R.R. #8	16.00	11.00	16.0000	310,000	49,600		
Natural Gas Pipeline Co. of America	Texas	Oklahoma	Panhandle	17.00	11.00	16.6000	30,990	5,144	G-18272	
El Paso Natural Gas Co.; Hunt Oil Co.	Upton	Texas	R.R. #7-C	16.00	11.00	13.6822	64,718	8,855	G-20523	
Montana-Dakota Utilities Company	Park	Wyoming	Wyoming	15.00	12.70	7.8003	26,619	2,076		
Consolidated Gas Utilities Corp.	Grady	Oklahoma	Other	15.00	11.00	11.0000	Indeterminable	--		
Texas Gas Gathering Corp.	Texas	Louisiana	No. La.	16.60¢/	13.70¢/	14.1381	457,827	64,728		
Panhandle Eastern Pipeline Company	Seward	Kansas	Kansas	16.00	11.00	15.0000	960,000	144,000		
Panhandle Eastern Pipeline Company	Hansford	Texas	R.R. #10	17.00	11.00	16.0000	72,000	11,520		
El Paso Natural Gas Company	Reagan	Texas	R.R. #7-C	16.00	11.00	17.2295	177,401	30,565	G-20405	
Trunkline Gas Company	Brazoria	Texas	R.R. #3	18.00	14.00	20.0000	9,300,000	1,860,000		
Trunkline Gas Company	Galveston	Texas	R.R. #3	18.00	14.00	20.0000	5,580,000	1,116,000		
United Gas Pipe Line Company	Panola	Texas	R.R. #6	15.00	14.00	13.0000	495,876	64,464		
Cities Service Gas Company	Barber	Kansas	Kansas	16.00	11.00	13.0000	106,884	13,895	G-20339	
United Gas Pipe Line Company	San Patricio, Nueces	Texas	R.R. #4	18.00	14.00	14.8000	246,600	36,497		
Lone Star Gas Company	Carter	Oklahoma	Other	15.00	11.00	13.3000[3]	30,000	3,990	RI60-201	

Comparison of Prices Under "New" Rate Schedules,* Not Included in Docket No. G-1148 et al., With Area Rate Standards Set Forth in Statement of General Policy No. 61-1 and First Amendment Thereto

Rate Schedule Number	Purchaser	County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60	Latest Indicated Annual Volume
324	Lone Star Gas Company	Carter	Oklahoma	Other	15.00¢	11.00¢	16.8000 4/¢	43,000
325	Cities Service Gas Company	Garvin	Oklahoma	Other	15.00	11.00	11.0000	4,320,000
326	Natural Gas Pipeline Co. of America	Jack	Texas	R.R. #9	14.00	14.00	13.0000	1,488,000
327	Panhandle Eastern Pipeline Company	Reno	Kansas	Kansas	16.00	11.00	13.0000	337,500
328	United Gas Pipe Line Company	Refugio	Texas	R.R. #2	18.00	14.00	12.1536	306,720
329	Commonwealth Oil Company	Vermilion	Louisiana	So. La.	20.96 1/	13.70 1/	19.9234 5/	22,891,325
330	Tennessee Gas Transmission Company	Cameron	Louisiana	So. La.	20.96 1/	13.70 1/	22.2634	4,451,486
331	West Texas Gathering Company	Winkler	Texas	R.R. #8	16.00	11.00	16.0000	540,000
332	Natural Gas Pipeline Co. of America	Beaver	Oklahoma	Panhandle	17.00	11.00	16.8000	231,223
333	Not Available							
336	Northern Natural Gas Company	Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	43,200
338	El Paso Natural Gas Company	Lea	New Mexico	Permian Basin	16.00	11.00	17.0657	185,401
339	Coastal States Gas Producing Company	Bee	Texas	R.R. #2	18.00	14.00	10.0000	396,012
340	Not Available							
341	Cities Service Gas Company	Harper	Oklahoma	Panhandle	17.00	11.00	12.0000	651.000
342	Transcontinental Gas P. L. Corp.	Terrebonne	Louisiana	So. La.	20.96 1/	13.70 1/	23.4498	763,044
343	Wunderlick Development Company	Kay	Oklahoma	Other	15.00	11.00	6.2000	21,600
344	Lone Star Gas Company	Grady, Stephens	Oklahoma	Carter Knox	16.80	11.00	16.8000	12,000
345	New York State Natural Gas Corp.	Potter	Pennsylvania	Pennsylvania			26.2887	381,357
346	Kerr-McGee Oil Industries, Inc., & Rock-Pam Gas Gathering	Gray	Texas	R.R. #10	17.00	11.00	12.0000	2,976,000
347	Texas Gas Transmission Corp.	Webster	Louisiana	No. La.	16.60 1/	13.70 1/	13.4068	53,413
348	Texas Gas Transmission Corp.	Webster, Claiborne	Louisiana	No. La.	16.60 1/	13.70 1/	17.7945	371,984
349	Texas Gas Transmission Corp.	Webster	Louisiana	No. La.	16.60 1/	13.70 1/	15.3569	272,050
350	Transcontinental Gas P. L. Corp.	St. Mary	Louisiana	So. La.	20.96 1/	13.70 1/	21.4509	
		Cameron	Louisiana	So. La.	20.96 1/	13.70 1/	23.2060	11,445,663
351	Michigan Wisconsin Pipe Line Co.	Harper, Beaver	Oklahoma	Panhandle	17.00	11.00	17.0000	360,000
352	Coastal Transmission Corp.	Nueces	Texas	R.R. #4	18.00	14.00	16.5000	945,000
353	Panhandle Eastern Pipeline Company	Texas	Oklahoma	Panhandle				
		Hansford	Texas	R.R. #10	17.00	11.00	16.0000	360,000
354	Southern Natural Gas Company	St. Martin	Louisiana	So. La.	20.96 1/	13.70 1/	22.6697	738,430
355 7/	Hope Natural Gas Company	Cameron	Louisiana	So. La.	20.96 1/	13.70 1/	22.9622	1,927,302
356 7/	Panhandle Eastern Pipeline Company	Moore	Texas	R.R. #10	17.00	11.00	10.0000	6,208,838
357	Not Available							
358	El Paso Natural Gas Company	Crockett	Texas	R.R. #7-C	16.00	11.00	14.6958	63,366
359	El Paso Natural Gas Company	Winkler	Texas	R.R. #8	16.00	11.00	17.1632	2,555,000
360	United Gas Pipe Line Company	Jackson	Texas	R.R. #2	18.00	14.00	14.0018	518,172
361	Northern Natural Gas Company	Harper	Oklahoma	Panhandle	17.00	11.00	15.0000	15,324
362	Colorado Interstate Gas Company	Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	180,000

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Purchaser	County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60	Latest Indicated Annual Volume	Annual Revenue at 1960 Filed Rate	Docket Numbers $ 4e Proceedings	Docket Numbers Certificate Proceedings**
Lone Star Gas Company	Carter	Oklahoma	Other	15.00¢	11.00¢	16.8000[4]¢	43,000	$ 7,224	RI60-201	
Cities Service Gas Company	Garvin	Oklahoma	Other	15.00	11.00	11.0000	4,320,000	475,200		
Natural Gas Pipeline Co. of America	Jack	Texas	R.R. #9	14.00	14.00	13.0000	1,488,000	193,440		
Panhandle Eastern Pipeline Company	Reno	Kansas	Kansas	16.00	11.00	13.0000	337,500	43,875		
United Gas Pipe Line Company	Refugio	Texas	R.R. #2	18.00	14.00	12.1536	306,720	37,278		
Commonwealth Oil Company	Vermilion	Louisiana	So. La.	20.96[1]/	13.70[1]/	19.9234[5]/	22,891,325	4,560,730		Pending
Tennessee Gas Transmission Company	Cameron	Louisiana	So. La.	20.96[1]/	13.70[1]/	22.2634	4,451,486	991,052		Pending
West Texas Gathering Company	Winkler	Texas	R.R. #8	16.00	11.00	16.0000	540,000	86,400		Withdrawn
Natural Gas Pipeline Co. of America	Beaver	Oklahoma	Panhandle	17.00	11.00	16.8000	231,223	38,845	RI60-169	
Not Available										
Northern Natural Gas Company	Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	43,200	6,480		
El Paso Natural Gas Company	Lea	New Mexico	Permian Basin	16.00	11.00	17.0657	185,401	31,640	G-20405	
Coastal States Gas Producing Company	Bee	Texas	R.R. #2	18.00	14.00	10.0000	396,012	39,601		
Not Available										
Cities Service Gas Company	Harper	Oklahoma	Panhandle	17.00	11.00	12.0000	651.000	78,120		
Transcontinental Gas P. L. Corp.	Terrebonne	Louisiana	So. La.	20.96[1]/	13.70[1]/	23.4498	763,044	178,932		Cert.not yet accepted
Wunderlick Development Company	Kay	Oklahoma	Other	15.00	11.00	6.2000	21,600	1,339		
Lone Star Gas Company	Grady, Stephens	Oklahoma	Carter Knox	16.80	11.00	16.8000	12,000	2,016		
New York State Natural Gas Corp.	Potter	Pennsylvania	Pennsylvania			26.2887	381,357	100,254		
Kerr-McGee Oil Industries, Inc., & Rock-Pam Gas Gathering	Gray	Texas	R.R. #10	17.00	11.00	12.0000	2,976,000	357,120		
Texas Gas Transmission Corp.	Webster	Louisiana	No. La.	16.60[1]/	13.70[1]/	13.4058	53,413	7,161		
Texas Gas Transmission Corp.	Webster, Claiborne	Louisiana	No. La.	16.60[1]/	13.70[1]/	17.7945	371,984	66,193		
Texas Gas Transmission Corp.	Webster	Louisiana	No. La.	16.60[1]/	13.70[1]/	15.3569	272,050	41,778		
Transcontinental Gas P. L. Corp.	St. Mary	Louisiana	So. La.	20.96[1]/	13.70[1]/	21.4509				
	Cameron	Louisiana	So. La.	20.96[1]/	13.70[1]/	23.2060	11,445,663	2,555,588[6]/		
Michigan Wisconsin Pipe Line Co.	Harper, Beaver	Oklahome	Panhandle	17.00	11.00	17.0000	360,000	61,200		Temp. cert.
Coastal Transmission Corp.	Nueces	Texas	R.R. #4	18.00	14.00	16.5000	945,000	155,925		
Panhandle Eastern Pipeline Company	Texas	Oklahoma	Panhandle							
	Hansford	Texas	R.R. #10	17.00	11.00	16.0000	360,000	57,600		
Southern Natural Gas Company	St. Martin	Louisiana	So. La.	20.96[1]/	13.70[1]/	22.6697	738,430	167,400		
Hope Natural Gas Company	Cameron	Louisiana	So. La.	20.96[1]/	13.70[1]/	22.9622	1,927,302	442,551		
Panhandle Eastern Pipeline Company	Moore	Texas	R.R. #10	17.00	11.00	10.0000	6,208,838	620,884		
Not Available										
El Paso Natural Gas Company	Crockett	Texas	R.R. #7-C	16.00	11.00	14.6958	63,366	9,312	RI60-2	
El Paso Natural Gas Company	Winkler	Texas	R.R. #8	16.00	11.00	17.1632	2,555,000	438,520	RI61-30	
United Gas Pipe Line Company	Jackson	Texas	R.R. #2	18.00	14.00	14.0018	518,172	72,553		Temp. cert.
Northern Natural Gas Company	Harper	Oklahoma	Panhandle	17.00	11.00	15.0000	15,324	2,299		Pending
Colorado Interstate Gas Company	Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	180,000	27,000		Temp. cert.

Comparison of Prices Under "New" Rate Schedules,* Not Included in Docket No. G-1148 et al., With Area Rate Standards Set Forth in Statement of General Policy No. 61-1 and First Amendment Thereto

Rate Schedule Number	Purchaser	County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60	Indicated Annual Volume	Annual Revenue at 1960 Filed Rate
363	El Paso Natural Gas Company	Reeves	Texas	R.R. #8	16.00¢	11.00¢	14.6958¢	2,358,509	346,602
364	Transwestern Pipe Line Company	Roberts	Texas	R.R. #10	17.00	11.00	17.0000 8/	744,000	126,480
365	Cities Service Gas Company	Woodward	Oklahoma	Panhandle	17.00	11.00	15.0000	540,000	81,000
366	Cities Service Gas Company	Woodward	Oklahoma	Panhandle	17.00	11.00	15.0000	2,256	338
367	Northern Natural Gas Company	Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	72,000	10.800
368	Transwestern Pipe Line Company	Pecos	Texas	R.R. #8	16.00	11.00	16.0000	372,000	59,520
369	Not Available								
370 9/	Texas Eastern Transmission Corp.	Lincoln	Louisiana	No. La.	16.60 1/	13.70 1/	15.4063	126,000	19,412
371 9/	Henderson Trust	Hutchinson	Texas	R.R. #5	14.00	14.00	11.0000	73,781	8,116
							Total	131,891,928	$24,820,718

* The last rate schedule included in Phillips' Exhibit 223 was #270; this tabulation includes Rate Schedules #271 through #371, excluding those which are no longer i head and liquids contracts.

** Permanent certificates have been issued by the Commission authoriz enumerated rate schedules, except as noted.

1/ Excludes tax.

2/ Supersedes Rate Schedule #242.

3/ Excludes compression charge.

4/ Less 3.5¢ for miscellaneous.

5/ Excludes 2.4¢ gathering charge.

6/ Using 22.328¢ as the price.

7/ Supersedes Rate Schedules 52, 61, 143, 270.

8/ Conditioned price.

9/ Supersedes Rate Schedule 60.

Source: Phillips Petroleum Company Rate Schedules, supplements and billing statements on file with the Federal Power Commission. Federal Power Commission, Statement No. 61-1, Issued September 28, 1960; First Amendment to Statement of General Policy No. 61-1, Issued October 25, 1960.

Comparison of Prices Under "New" Rate Schedules,* Not Included in Docket No. G-1148 et al., With Area Rate Standards Set Forth in Statement of General Policy No. 61-1 and First Amendment Thereto

County	State	Area Designation	F.P.C. AREA PRICE (14.65 Psia) New Gas	F.P.C. AREA PRICE (14.65 Psia) Old Gas	Filed Rate as of 9/28/60	Indicated Annual Volume	Annual Revenue at 1960 Filed Rate	Docket Numbers § 4e Proceedings	Docket Numbers Certificate Proceedings**
Reeves	Texas	R.R. #8	16.00¢	11.00¢	14.6958¢	2,358,509	346,602	G-20417	
Roberts	Texas	R.R. #10	17.00	11.00	17.0000	744,000	126,480		Temp. cert.
Woodward	Oklahoma	Panhandle	17.00	11.00	15.0000	540,000	81,000		Temp. cert.
Woodward	Oklahoma	Panhandle	17.00	11.00	15.0000	2,256	338		Temp. cert.
Beaver	Oklahoma	Panhandle	17.00	11.00	15.0000	72,000	10.800		Temp. cert.
Pecos	Texas	R.R. #8	16.00	11.00	16.0000	372,000	59,520		Temp. cert.
Lincoln	Louisiana	No. La.	16.60 1/	13.70 1/	15.4063	126,000	19,412		Temp. cert.
Hutchinson	Texas	R.R. #5	14.00	14.00	11.0000	73,781	8,116		Pending
					Total	131,891,928	$24,820,718		

ps' Exhibit 223 was #270; this tabulation includes Rate Schedules #271 through #371, excluding those which are no longer in effect and casing-

** Permanent certificates have been issued by the Commission authorizing service under the enumerated rate schedules, except as noted.

ules, supplements and billing statements on file with the Federal Power Commission. Federal Power Commission, Statement of General Policy endment to Statement of General Policy No. 61-1, Issued October 25, 1960.

PHILLIPS PETROLEUM CO., SECTION 4-e RATE SUSPENSION PROCEEDINGS NOT CONSOLIDATED WITH DOCKET NO. G 1148 ET AL AND PENDING AS OF SEPTEMBER 28, 1960

Purchaser	Rate Schedule No.	Docket No.	Annual Amount Suspended	Effective Subject to Refund
Arkansas - Louisiana Gas Co.	31	G 16,113	2,359	2/26/59
Cities Service Gas Co.	257-298-321	G 20,339	1,527	-
Colorado Interstate Gas Co.	10-57-66	G 18,215	27,880	9/18/59
Colorado Interstate Gas Co.	21	G 11,622	146,897	6/1/57
Colorado Interstate Gas Co.	21	G 20,561	151,134	-
Colorado Interstate Gas Co.	240	G 17,783	428	7/22/59
Consolidated Gas Utilities Corp.	19	G 12,460	63,275	10/12/59
Consolidated Gas Utilities Corp.	19	G 14,930	93,522	10/12/59
Consolidated Gas Utilities Corp.	19	G 18,273	61,302	10/12/59
Consolidated Gas Utilities Corp.	150	G 14,686	2,752	8/27/58
Consolidated Gas Utilities Corp.	19	RI 60-394	288,600	
El Paso Nat. Gas Co.	(Oper.) 7-9-32-33-64-243	G 14,115	3,637,284	6/1/58
El Paso Nat. Gas Co.	(Oper.) 7-9-32-64-243	G 18,417	2,212,624	-
El Paso Nat. Gas Co.	(Oper.) 7-9-64-243	G 20,404	1,090,103	-
El Paso Nat. Gas Co.	10	G 13,734	138,052	5/14/58
El Paso Nat. Gas Co.	10-57-66	G 18,215	27,880	9/18/59
El Paso Nat. Gas Co.	10-47-66-151-260-315-338	G 20,405	137,381	-
El Paso Nat. Gas Co.	(Oper.) et al 32-33-40-65-256-274	G 20,403	3,385,616	-
El Paso Nat. Gas Co.	(Oper.) et al 33	G 18,418	354,443	-
El Paso Nat. Gas Co.	66	G 14,007	3,263	6/1/58
El Paso Nat. Gas Co.	66	G 15,315	1,751	12/1/58
El Paso Nat. Gas Corp.	(Oper.) et al 256	G 14,006	66	6/1/58
El Paso Nat. Gas Corp.	(Oper.) et al 256	G 15,314	145	12/1/58
El Paso Nat. Gas Corp.	(Oper.) et al 256	G 18,206	960	9/13/59

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PHILLIPS PETROLEUM CO., SECTION 4-e RATE SUSPENSION PROCEEDINGS NOT CONSOLIDATED WITH DOCKET NO. G 1148 ET AL AND PENDING AS OF SEPTEMBER 28, 1960

Purchaser	Rate Schedule No.	Docket No.	Annual Amount Suspended	Effective Subject to Refund
El Paso Nat. Gas Co.	309	G 18,207	830	9/13/59
	1	RI60-2	4,101	
	359	RI60-15	150,000	
	359	RI61-30	25,800	
Henderson Trusts	60	RI60-336	7,200	
Hunt Oil Co.	309	G 18,207	830	9/13/59
Kansas-Nebraska Natural Gas Co., Inc.	302	G 16,311	37	3/1/59
Kansas-Nebraska Natural Gas Co., Inc.	302	G 19,474	24	-
Kansas-Nebraska Natural Gas Co., Inc.	247	RI60-93	n/a	
La-Tex Petroleum Products Corp.	(Oper.) et al 218-246	G 16,600	181,125	-
Lone Star Gas Co.	158	G 14,008	-	6/1/58
Lone Star Gas Co.	(Oper.) et al 323	G 16,333	278	3/1/59
Lone Star Gas Co.	324	G 16,339	830	3/1/59
Lone Star Gas Co.	323-24	RI60-201	4,200	
Michigan Wisconsin P/L Co.	4	G 19,032	1,610,504	-
Michigan Wisconsin P/L Co.	4	RI60-349	1,634,600	
Mississippi River Fuel Corp.	22	G 12,283	142	9/3/57
Mississippi River Fuel Corp.	22	RI60-257	350	
Natural Gas P/L Co. of America	257	G 11,723	240	6/24/57
Natural Gas P/L Co. of America	257	G 14,258	177	6/23/58
Natural Gas P/L Co. of America	257-298	G 17,429	478	6/23/59
Natural Gas P/L Co. of America	257-298-321	G 20,339	1,527	-
Natural Gas P/L Co. of America	292-307	G 18,272	122	10/10/59
Natural Gas P/L Co. of America	298	G 14,555	323	7/28/58
Natural Gas P/L Co. of America	307	G 15,013	52	10/10/58
Natural Gas P/L Co. of America	332	G 17,878	499	8/21/59
Natural Gas P/L Co. of America	332	RI60-169	460	

PHILLIPS PETROLEUM CO., SECTION 4-e RATE SUSPENSION PROCEEDINGS NOT CONSOLIDATED WITH DOCKET NO. G 1148 ET AL AND PENDING AS OF SEPTEMBER 28, 1960

Purchaser	Rate Schedule No.	Docket No.	Annual Amount Suspended	Effective Subject to Refund
Northern Natural Gas Co.	24	G 11,641	236,867	6/1/57
Northern Natural Gas Co.	(Oper.) 24	G 17,295	72,528	6/1/59
Northern Natural Gas Co.	176	G 15,088	44	10/24/58
Northern Natural Gas Co.	252	G 14,009	9,132	6/1/58
Northern Natural Gas Co.	262	G 16,178	84,816	3/1/59
Northern Natural Gas Co.	(Oper.) et al 262	G 19,473	89,943	-
Northern Natural Gas Co.	(Oper.) 262	RI60-226	802,600	
Northern Natural Gas Co.	58	RI60-277	980	
Pacific Northwest P/L Corp.	279	G 16,713	34,657	3/25/59
Panhandle Eastern P/L Co.	(Oper.) 5	G 16,112	384,006	9/2/58
Panhandle Eastern P/L Co.	(Oper.) 5	G 19,845	2,717,526	-
Panhandle Eastern P/L Co.	(Oper.) 5	G 20,5[illegible]0	-	-
Permian Basin P/L Co.	18	G 11,849	298,560	7/8/57
Permian Basin P/L Co.	(Oper.) 18	G 17,071	363,567	5/1/59
Southern Natural Gas Co.	219	G 16,083	364,702	-
Southern Natural Gas Co.	219	G 17,920	85,096	8/9/59
Southern Natural Gas Co.	299-300	G 17,156	83,233	5/13/59
Southern Natural Gas Co.	301	G 17,267	28,398	5/18/59
Tennessee Gas Trans. Co.	3-30-43	G 20,542	12,722	-
Tennessee Gas Trans. Co.	(Oper.) et al 20	G 20,543	5,698	-
Tennessee Gas Trans. Co.	(Oper.) et al 29	G 17,136	9,078	6/1/59
Tennessee Gas Trans. Co.	(Oper.) et al 34	G 17,086	3,161	6/1/59
Tennessee Gas Trans. Co.	36-209-231	G 17,280	64,776	6/1/59
Tennessee Gas Trans. Co.	39	G 17,139	3,025	6/1/59
Tennessee Gas Trans. Co.	200	G 17,277	3,604	6/1/59
Tennessee Gas Trans. Co.	(Oper.) et al 218-246	G 16,600	181,125	-
Tennessee Gas Trans. Co.	(Oper.) et al 218	G 18,414	14,687	10/7/59

PHILLIPS PETROLEUM CO., SECTION 4-e RATE SUSPENSION PROCEEDINGS NOT CONSOLIDATED WITH DOCKET NO. G 1148 ET AL AND PENDING AS OF SEPTEMBER 28, 1960

Purchaser	Rate Schedule No.	Docket No.	Annual Amount Suspended	Effective Subject to Refund
Texas Eastern Trans. Corp.	2-A	G 11,309	6,441	4/1/57
Texas Eastern Trans. Corp.	2-A	G 13,419	5,617	4/1/58
Texas Eastern Trans. Corp.	2A-275-281	G 20,255	17,369	-
Texas Eastern Trans. Corp.	2A-286	G 16,625	6,608	4/1/59
Texas Eastern Trans. Corp.	286	G 13,398	191	4/1/58
Texas Eastern Trans. Corp.	286	G 19,581	31	-
Texas Eastern Trans. Corp.	2A	RI60-367	7,100	
Texas Gas P/L Corp.	145	G 11,326	1,308	4/1/57
Texas Gas P/L Corp.	145	G 13,420	2,291	4/1/58
Texas Gas P/L Corp.	145	G 17,137	2,068	5/4/59
Texas Gas P/L Corp.	145	G 19,950	35,151	-
Texas Gas Trans. Corp.	202	G 11,991	34,082	7/15/57
Texas Illinois Nat. Gas P/L Co.	41	G 12,685	22,813	11/9/57
Transcontinental Gas P/L Corp.	149-220	G 17,740	85,940	7/9/59
United Fuel Gas Co.	273	G 14,260	61,902	5/16/58
United Fuel Gas Co.	273	G 16,712	43,435	4/1/59
United Fuel Gas Co.	273	G 20,013	135,337	-
United Gas P/L Co.	216	G 20,352	167,659	-
West Lake Natural Gasoline Co.	316	G 15,994	535	8/25/58
West Lake Natural Gasoline Co.	316	G 20,349	3,092	-
West Lake Natural Gasoline Co.	316	RI60-390	3,100	
			22,050,574	

Source: Federal Power Commission Records

* * * * * * * * * * *

32897

Order Denying Applications for Rehearing, Amending Opinion and Rejecting Application for Rehearing

(Issued November 25, 1960)

Under the provisions of Section 19(a) of the Natural Gas Act applications for rehearing have been filed with respect to the Commission's opinion and order No. 338, issued September 28, 1960. Timely applications were filed by Minneapolis Gas Company, the State and the Public Service Commission of Wisconsin, the Michigan Public Service Commission, Public Service Electric and Gas Company, the State and Public Utilities Commission of California and the Eastern Seaboard Companies.[1] An application for rehearing was filed by the Public Service Commission of New York, but it arrived after the termination of the statutory period within which such applications may be filed. A response to the applications for rehearing was filed by Phillips, and reply was made by the Eastern Seaboard Companies but we rejected Phillips response. A number of the points raised by the applications for rehearing have been sufficiently answered in the original opinion and needn't be discussed again. The principal points raised by the applications concern our authority to terminate these proceedings.

Minneapolis Gas argues that we have no authority to terminate the Section 5(a) investigation and Section 4(e) proceedings without making any finding as to the justness and reasonableness of Phillips' rates. We did not make such a finding because we did not believe we were supported by the record in doing so, and we were of the opinion that the public interest

[1] Long Island Lighting Company, Philadelphia Electric Company, and the United Gas Improvement Company.

did not justify our continuing these proceedings. In the first place we are given discretion as to whether to initiate proceedings either under Section 5(a) or Section 4(e). Section 5(a) provides that "Whenever the Commission, after a hearing had upon its own motions or upon complaint . . . shall find that any rate . . . is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate. . ." Under Section 4(e), relating to rate filings, "Whenever any such new schedule is filed the Commission shall have authority, either upon complaint . . ., or upon its own initiative without complaint . . . to enter upon a hearing concerning the lawfulness of such rate, . . .".

Just as the statute leaves us with discretion as to whether to initiate proceedings, we have authority to discontinue the proceedings. Regulation under the Natural Gas Act is carried on in the public interest (Section 1(a)), and there is no obligation to continue these proceedings to the point of making a definitive finding with respect to Phillips' rates, where the public interest is not served. Section 16 provides, "The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act." We may now turn again to the basis for terminating these proceedings.

As we stated in our opinion, on the basis of the record and the test year 1954, we cannot reach a decision on cost of service applicable to the years after the issuance of our opinion and order. The Eastern Seaboard Companies argue that we should grant rehearing, consolidate all of Phillips' Section 4(e) proceedings and direct Phillips to submit a 1959 cost of service determination based on Opinion No. 338 as well as revised rate schedules designed to return its

current costs. This, of course, would require reopening the record and the submission of completely new evidence. For the future it is our judgment that the interest of consumers and the exigencies of regulation will be better served in rate proceedings brought on an area basis rather than on an individual company basis. Therefore, we do not think it in the public interest to reopen these proceedings, to determine a cost of service on the basis of completely new evidence and to attempt to determine rates on the basis of Phillips' individual cost of service.

The basis of our decision to terminate the dozen Section 4(e) dockets was that the rates filed in those dockets produced less revenues than the cost of service determined in our opinion. The fact that some of these rates are in excess of the average cost of service determined by us is immaterial. Phillips' rates would normally vary greatly because the sales are made at widely separated points and under different conditions, and there is nothing to show that these rates are discriminatory or preferential. In our judgment there is little or nothing to be gained for the consumer by continuing a complicated proceeding so as to determine just and reasonable rates for Phillips when it is already known that Phillips was not earning

its whole cost of service. To conclude, the attempt here to regulate Phillips' rates on an individual company basis has proved cumbersome and inexact. It has demonstrated however, that there is no public interest in continuing the Section 4(e) proceedings, which are largely concerned with past periods. Furthermore, because of the lapse of time, the 1954 cost of service determined by us is not appropriate for the future. The more recent rate increases filed with us have been suspended under Section 4(e), and they will be subject to the new area methods of regulation discussed in our Policy Statement. In this way we can proceed to a

more effective and expeditious regulation of the producer sales.

A few additional comments are appropriate on other points. Wisconsin objects to our including in the rate base $8,430,758 representing net investment in the San Juan Basin producing leases which were transferred to Pacific Northwest Pipe Line Corporation in November, 1955, after the end of the test year. We included these reserves because the record showed that they would be more than replaced after the test year, so that the San Juan Reserves did not abnormally inflate the test year rate base. Wisconsin argues that since we were not determining rates for the future it was inappropriate to include these reserves. We were not determining rates for the future as of the time of our opinion, but, we were determining a cost of service for the future from the standpoint of the test year. That is, our cost of service would apply to the test year 1954 and for a reasonable time thereafter.

Wisconsin also objects to our granting to Phillips a return of 11 percent on its rate base. It says that we are confusing the physical risk of producing gas with the financial risk assumed by investors. It adds that the physical risk is compensated for by the allowance of the cost of exploration development and production as an expense to Phillips in determining its cost of service. The financial risk, Wisconsin, in effect, says, is covered by the evaluation of the securities market as reflected in the earnings-price ratio, which we used as a factor in arriving at a fair rate of return. We do not think the situation is as simple as this. We must not only reflect past expenses in the cost of service and past risks in the rate of return, but as shown by our opinion, we must reflect the increasing expense and increasing risks of obtaining a gas supply. Therefore, as explained in our opinion, the use of 12 percent as an allowance for common equity and 11 percent for a fair rate of return was appropriate.

Wisconsin also objects to our reference to the spiral escalation clauses in Phillips' contracts as providing customer consent to Phillips' proposed rate increases. It may be recalled that these clauses provide for a contractual increase in Phillips' rates when its customer pipeline obtains an increase. Wisconsin says that they would purport to effect a change in rate between Phillips and its pipeline customers without compliance with Sections 4 or 5 of the Natural Gas Act and are therefore void as a matter of law. While the spiral clauses might change the contractual rights of the parties, Phillips can only change its rates by an appropriate filing under Section 4 of the Act.

32900

The Public Service Commission of the State of New York (PSC) has filed an application for rehearing which was mailed October 27, 1960, but was received by us on October 31, 1960, more than 30 days after the issuance of our Opinion No. 338, on September 28, 1960. Section 19(a) of the Natural Gas Act provides that aggrieved parties "may apply for a rehearing within thirty days after the issuance of such order." As interpreted in our Rules "An application for rehearing of a proceeding may be *filed* within 30 days after the issuance of any final decision or order by the Commission." (Section 1.34(a))[2] Therefore the application of PSC was not timely and must be rejected. Actually the application was directed to some of the same problems covered by the other applications for rehearing, particularly

[2] Section 1.14(a)(1) of our Rules provides:

"The filing of written applications, complaints, declarations, petitions, protests, answers, motions, briefs, exceptions, rate schedules, notices, reports, or other pleadings, amendments to pleadings, documents, or papers, with the Commission as required or allowed by these rules, by any rule, regulation, or order of the Commission, or by any applicable statute, shall be made by filing them with the Office of the Secretary of the Commission in Washington, D. C. Any such papers must be received by the Commission in Washington, D. C., within the time limit, if any, for such filing.

our decision not to determine Phillips' rates for the future, so that if we had accepted PSC's application for rehearing we would not have reached a different conclusion.

It has come to our attention that certain revisions should be made in the computation of Phillips' cost of service as set forth in appendices 9 and 10. To effect these revisions, amended appendices 9 and 10 are attached herewith. The purpose of the revisions is to correct the computation, to make explicit the treatment accorded the cost of raw gas, and to show gas used as compressor station and plant fuel gas separate from extraction losses and the treatment of its cost. The new computation in appendix 9, like the previous one,[3] shows the total gas produced and purchased amounting to 783,675,122 Mcf. This is divided, as before, on the basis of volumes into field sales and total gas gathered, the latter amounting to 687,145,852 Mcf. The total gas gathered on the basis of volumes is distributed to raw gas sales in the amount of 18,845,896 and residue gas sales from the system in the amount of 573,436,146, leaving 62,581,197 Mcf representing the loss involumes from the extraction of the liquids, residue returned to leases and gas vented, and 32,282,613 Mcf representing compressor station and plant fuel and unaccounted for gas. Conversion is

then made into Btu's using 1151 Btu's per cubic foot for the gathered gas and 1063 Btu's per cubic foot for the residue gas. From the Btu figures obtained, percentages are derived showing that of the gas gathered, after subtraction of the raw gas sales, 16.7328 percent is allocable to extraction losses etc. and 83.2672 percent is allocable to residue gas sales.

These percentages are employed in appendix 10 in computing the cost of service as described in our opinion.[4] As

[3] See our previous opinion, mimeo. p. 35.

revised we arrive at a jurisdictional cost of service of $54,525,315 or 11.1009 cents per Mcf, subject to redetermination for purchased gas costs, gathering taxes and royalties.

The Commission further finds:

The assignments of error and grounds for rehearing in the above applications for rehearing set forth no new facts or principles of law which were not fully considered by the Commission when it issued its opinion and order September 28, 1960, or which having now been considered warrant any change or modification of said order except as noted above. Such specifications of error, contentions and arguments contained in the above application for rehearing as are not specifically disposed of in the foregoing are without reasonable basis in law, or are immaterial to the correct decision of this case, and should be denied.

The Commission orders:

(A) The applications for rehearing filed by Minneapolis Gas Company, the State of Wisconsin and the Public Service Commission of Wisconsin, the Michigan Public Service Commission, Public Service Electric and Gas Company, the State and Public Utilities Commission of California and the Eastern Seaboard Companies are hereby denied.

(B) Our opinion and order is hereby amended by substituting $54,525,315 or an average of 11.1009 cents per Mcf representing the cost of service, subject to adjustment of purchased gas costs, gathering taxes and royalties for the amounts appearing in our opinion and order particularly on pages 49, 51, and 54 (finding clause 2) and by substituting the figures appearing herein relating to the allocation of costs between residue gas and liquids for those ap-

[4] See Mimeo., p. 49.

pearing in our opinion, particularly on page 35. The attached appendices 9 and 10 are hereby substituted for the prior appendices 9 and 10.

(C) The Application of the Public Service Commission of New York is hereby rejected.

By the Commission. Commissioner Kline concurring in the result. Commissioner Sweeney not participating.

32903

PHILLIPS PETROLEUM COMPANY

Gas Balance and Allocation Percentages
Year, 1954

Appendix 9 (Revised)
Docket No. G-1148, et al.

Description		Distribution of Production								Gas Sales From System		
			Less: Field Sales									
		MCF	Non-Jurisdictional	Jurisdictional	Total Gas Gathered	Raw Gas System Sales	Balance	Extraction Loss, Residue Returned To Leases & Vented	Residue Gas Sales From Systems	Total	Non-Jurisdictional	Jurisdictional
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Gas Produced												
Dry Gas	226,681,178											
Casinghead Gas	70,510,228											
Condensate Gas	75,499,506											
Total		375,690,912	31,370,014	65,159,256	279,161,642							
Percent		100.0000	8.3500	17.3438	74.3062							
Gas Purchased												
Outside leases	336,373,922											
Outside Interest in Phillips Leases:												
Dry Gas	38,694,495											
Casinghead & Condensate Gas	32,915,793											
Total		407,984,210	.....	.....	407,984,210							
Total Produced & Purchased		783,675,122	31,370,014	65,159,256	687,145,852	18,845,896	668,299,956					
Compressor Station & Plant Fuel and Unaccounted For							32,282,613					
Sub-total							636,017,343	62,581,197	573,436,146	573,436,146		
						(18,845,896)	.....			18,845,896		
Total Gas Sales From Systems										592,282,042	166,262,345	426,019,697
Percent										100.0000	28.0715	71.9283
Btu (Per Cubic Foot)					1151	1151	1151	.....	1063			
Total Btu (Millions)					790,904,876	21,691,626	769,213,249	.....	.....			
Compressor Station & Plant Fuel and Unaccounted For							37,157,287					
Sub-total							732,055,962	122,493,339	609,562,623			
Percent					100.0000	2.7426	97.2574					
Percent							100.0000	16.7328	83.2672			

Summary of Jurisdictional Sales	*M.C.F*
Jurisdictional Sales From System	426,019,689
Jurisdictional Sales From Leases	65,159,256
Total Jurisdictional Sales	491,178,953

32904

PHILLIPS PETROLEUM COMPANY
Jurisdictional Cost of Service
Year 1954

Appendix 10 (Revised)
Docket No. G-1148, et al.

Description	Volume	Total Cost of Gas	Field Sales: Non-Jurisdictional	Field Sales: Jurisdictional	Delivered to Gathering Systems	Less Raw Gas System Sales	Balance	Extraction Losses, Returned to Leases & Vented	Total Cost of Residue System Sales	Cost of Sales from Systems: Total	Cost of Sales from Systems: Non-Jurisdictional	Cost of Sales from Systems: Jurisdictional
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						Col.(6)x2.7426%		Col.(8)x16.7328%	Col. 8-Col. 9			
Percent		100.0000	8.3500	17.3438	74.3063					100.0000	28.0715	71.9285
Cost of Gas Production & Exploration												
Direct and Allocated	376,690,912	$ 37,924,378	$ 3,166,686	$ 6,577,528	$ 28,180,164							
Purchased Gas	407,984,210	30,320,225	.....	.....	30,320,225							
Total		$ 68,244,603	$ 3,166,686	$ 6,577,528	$ 58,500,389	$ 1,604,432	$ 56,895,957	$ 9,520,287	$ 47,375,670	$ 47,375,670		
Gathering System & Compressing Facilities		18,452,321			18,452,321	506,073	17,946,248	3,002,910	14,943,338	14,943,338		
Residue System		1,674,725			1,674,725		1,674,725	.....	1,674,725	1,674,725		
Sub-total		$ 88,371,649			$ 78,627,435	$ 2,110,505	$ 76,516,930	$ 12,523,197	$ 63,993,733	$ 63,993,733		
Raw Gas Sales						(2,110,305)				2,110,505		
						$						
Total										$ 66,104,236	$ 18,556,451	$ 47,547,757

Summary of Jurisdictional Cost of Service

Jurisdictional Sales From Systems Col. (13)		$ 47,547,787
Jurisdictional Sales From Leases Col. (5)		6,577,526
Regulatory Commission Expense		400,000
Total Jurisdictional Cost of Service		$ 54,525,315
	Cost For M.C.F	
$ 54,323,315	$491,178,953	11.1009¢

* * * * * * * * * *

32909

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 11247

STATE OF WISCONSIN and PUBLIC SERVICE COMMISSION OF WISCONSIN, *Petitioners*

v.

FEDERAL POWER COMMISSION, *Respondent*

* * * * * * * * * *

32911

Before EDGERTON, CLARK, and PRETTYMAN, Circuit Judges.

EDGERTON, *Circuit Judge:*

* * * * * * * * * *

32919

Phillips urges that the Commission's findings are supported by substantial evidence and should therefore be sustained. But the validity or invalidity of the Commission's conclusion that Phillips is not a "natural-gas company" does not turn upon the evaluation of testimony or upon any facts peculiar to this case. It turns upon the generic question whether the exemption of "production or gathering" in § 1(b) of the Natural Gas Act covers interstate sales of gas by the corporation that produced and gathered it. We think the Act and the decisions of the Supreme Court permit only one answer. We think the Commission has applied an erroneous rule of law. Phillips' sales to the pipeline companies are not within either the statutory phrase "the production or gathering of natural gas" or the Supreme Court's paraphrase "made during the course of production and gathering". Therefore Phillips is a "natural-gas company" within the meaning

of the Natural Gas Act and the Commission should fix the rates at which these sales are made.[14]

Reversed

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32929

Before: Edgerton, Clark and Prettyman, Circuit Judges

JUDGMENT AND DECREE—Filed May 22nd, 1953

These cases came on to be heard on the transcript of the record from the Federal Power Commission, and were argued by counsel.

On consideration whereof, It is ordered, adjudged and decreed by this Court that the order of the said Federal Power Commission on review herein be, and the same is hereby, reversed, and that these cases be, and they are hereby, remanded to the Federal Power Commission for further proceedings in conformity with the opinion of this Court.

Per Circuit Judge Edgerton.

Separate dissenting opinion by Circuit Judge Clark.

* * * * * * * * * * *

[14] The Commission expressly recognizes that its decision to the contrary is subject to review.

32931

Docket No. G-1148

In the Matter of

PHILLIPS PETROLEUM COMPANY

Order Vacating Termination of Proceedings and Continuing Investigation

The Commission in its opinion issued August 22, 1951,[1] found, among other things, that Phillips Petroleum Company (Phillips) is not a natural-gas company within the meaning of Sections 1(b) or 2(6) of the Natural Gas Act, and by order accompanying that opinion the Commission terminated the proceeding initiated by its order issued October 29, 1948, in this docket, instituting an investigation to determine whether Phillips is a natural-gas company and, if so, whether in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged or collected, or any rules, regulations, practices or contracts affecting such rates, charges or classifications are unjust, unreasonable, unduly discriminatory, or preferential.

The United States Court of Appeals for the District of Columbia Circuit handed down its opinion[2] reversing the Commission and determined that Phillips is a natural-gas

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1 *In the Matter of Phillips Petroleum Company*, Docket No. G-1148, Opinion No. 217 and accompanying order, 10 F.P.C. 246, 283.

2 *State of Wisconsin* v. *F.P.C.*, 92 U.S. App. D.C. 284, 205 F. 2d 706.

company and that the "Commission should fix the rates" for Phillips' sales of natural gas for resale in interstate commerce. On June 7, 1954, the United States Supreme Court affirmed the opinion of the Court of Appeals.[3]

The judgment and decree of the Court of Appeals remanded the matter to the Commission for further proceedings in conformity with that Court's opinion.

32932

The Commission *finds:*

It is necessary and proper in the public interest, to aid in the enforcement of the Natural Gas Act, and in compliance with the mandate of the Court of Appeals, that our termination of the proceedings in this docket be vacated and that the investigation initiated by our order issued October 29, 1948, with respect to Phillips' rates and charges be continued.

The Commission *orders:*

(A) The termination of the proceedings in this docket directed by our order issued August 22, 1951, be and the same hereby is vacated.

(B) The investigation of Phillips Petroleum Company instituted by our order issued October 29, 1948, be and the same hereby is reinstituted and continued for the purpose of enabling the Commission to determine whether in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged or collected by Phillips, or any rules, regulations, practices or contracts affecting such rates, charges, or classifications

[3] *Phillips Petroleum Co.* v. *Wisconsin, et al.*, 347 U.S. 672.

are unjust, unreasonable, unduly discriminatory, or preferential.

(C) If the Commission shall find, after hearing, that any of Phillips' rates, charges, classifications, rules, regulations, practices, or contracts, subject to the jurisdiction of the Commission, are unjust, unreasonable, unduly discriminatory or preferential, it shall determine and fix, by order or orders, just and reasonable, nondiscriminatory and nonpreferential rates, charges, classifications, rules, regulations or contracts to be thereafter observed and in force.

By the Commission.

Adopted: November 17, 1954
Issued: November 22, 1954

[fol. 410]

IN UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 16175

STATE OF WISCONSIN and PUBLIC SERVICE COMMISSION OF WISCONSIN, Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, Intervenor.

No. 16177

LONG ISLAND LIGHTING COMPANY, et al., Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK, Intervenors.

No. 16180

PEOPLE OF THE STATE OF CALIFORNIA and PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, Intervenor.

[fol. 411]

On Petitions for Review of Order of the Federal Power Commission

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OPINION—Decided November 30, 1961

Mr. William E. Torkelson for petitioners in No. 16175.

Mr. J. David Mann, Jr., with whom Messrs. John E. Holtzinger, Jr., William W. Ross, and David K. Kadane were on the brief, for petitioners in No. 16177.

Mr. William M. Bennett for petitioners in No. 16180.

Mr. Arthur H. Fribourg, Attorney, Federal Power Commission, with whom Mr. John C. Mason, General Counsel, Federal Power Commission, at the time the brief was filed, and now Deputy General Counsel, and Mr. Howard E. Wahrenbrock, Solicitor, Federal Power Commission, were on the brief, for respondent.

Mr. Kenneth Heady, of the bar of the Supreme Court of Oklahoma, *pro hac vice*, by special leave of court, with whom Messrs. Charles E. McGee and Lambert McAllister were on the brief, for intervenor Phillips Petroleum Company.

Messrs. Kent H. Brown and George H. Kenny and Mrs. Barbara M. Suchow were on the brief for intervenor Public Service Commission of the State of New York in No. 16177.

Before Prettyman, Fahy and Danaher, Circuit Judges.

PRETTYMAN, Circuit Judge: Some controversies concern major problems of general application. Others concern only a limited set of circumstances. The case at bar is of the former variety. The questions are posed by complicated procedural difficulties. They concern the procedures of the Federal Power Commission in dealing with the rates of natural gas producers.

[fol. 412] The Phillips Petroleum Company is a producer of natural gas. It procures gas from several widely separated and widely differing areas. It explores for, develops, produces, purchases, gathers and processes gas and oil. It sells gas to pipeline companies[1] under contracts negotiated by it and these customers. The contracts differ in such terms as delivery conditions, water content, hydrocarbon content, place of delivery, pressure, and price.

[1] It also sells oil, products condensed from gas, and other petroleum products and chemicals. It sells natural gas in several conditions. It sells to customers other than pipelines as well.

Two sections of the Natural Gas Act[2] are involved. One (Section 4(e)) provides in essence, as to sales subjected to regulation by the Commission, that when a rate or an increased rate is filed the Commission may suspend it for five months, meantime setting it for hearing. When such a rate goes into effect after the period of suspension (the Commission not having concluded its consideration), the funds derived from the newly-filed rates may be impounded and, in so far as the Commission fails to approve them, may be refunded. The burden of proving in such a proceeding that an increased rate is "just and reasonable" rests upon the company. The other section of the statute (5(a)) provides in essence that either upon a complaint or upon its own motion the Commission may inquire into an existing rate. If that rate be found unlawful the Commission must determine what shall thereafter be deemed a just and reasonable rate. Its decision becomes effective from its date. No refund is involved.

In October, 1948, the Commission instituted a proceeding [fol. 413] under Section 5(a), the latter of the above sections, concerning Phillips's rates. In that proceeding it decided it had no jurisdiction over the rates of producers of natural gas. This court reversed the Commission,[3] and the Supreme Court affirmed our decision.[4] The Commission reinstated its 5(a) proceeding.

Meantime and thereafter Phillips filed increased rates in respect to many of its contracts. The Commission suspended them and set them for hearing, under Section 4(e) of the statute, the first of the two sections above discussed. Many purchasers, many contracts, many rate schedules, and many filings were involved. Thus many 4(e) proceedings, under different docket numbers, were instituted. As time went on, Phillips filed further proposed increases in some of these same rates. In such event the earlier proposed rate would, if approved, cover a limited period, *i.e.*, until the

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[2] 52 STAT. 821 (1938), as amended, 15 U.S.C. §§ 717-717w.

[3] State of Wisconsin v. Federal Power Comm'n, 92 U.S. App. D.C. 284, 205 F.2d 706 (1953).

[4] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

succeeding increase in that same contract rate was filed. A period thus limited is called a "locked-in period" in the jargon of the industry. These later increases were also suspended by the Commission. Thus many proceedings under Section 4(e) involving rates of Phillips became pending.

The Commission consolidated the 5(a) proceeding and twelve of the 4(e) proceedings for hearing. These twelve 4(e) proceedings involved an aggregate of about five and a half million dollars in proposed increased rates. The proposed rates ranged from 5¼ cents per Mcf to 13½ cents per Mcf. The proceeding was long, detailed and resulted in a voluminous record of testimony and exhibits. The Examiner rendered a long (174 printed pages), careful and complete initial decision. He approached the prob-
[fol. 414] lem from the standpoint of cost-of-service[5] and rate base. Many perplexing problems were presented. He examined them all and decided them. Among them were different approaches to cost-of-service, the allocation of production costs, the allocation of exploration costs, the problem of natural gas liquids, the rate base, adjustment to the test year, the computation of the income tax component, the proper rate of return, working capital, allocations between jurisdictional and non-jurisdictional sales, field prices, a discussion of system-wide as compared with area rates. Upon all these the Examiner made detailed findings and conclusions, displaying commendable patience and grasp of the subject matter. He adopted a system-wide approach and found that Phillips's total jurisdictional cost of service, properly computed, was $57,280,218 for the test year,[6] or an average unit cost of 11.662 cents per Mcf. He recommended that Phillips be ordered to calculate a maximum rate for gas with certain described qualities at such level that, when applied to the sales volume for all jurisdictional contracts, adjusted for approved delivery condition differentials, would produce revenues roughly equal to the system-wide cost of service. He recommended

[5] Cost-of-service in this context includes not only operating expenses, taxes, exploration allowances, and gas purchases but also a fair return on the rate base.

[6] Compared with 92.3 million dollars claimed by Phillips.

that Phillips be ordered to file, with full explanations, a list of rates so calculated. These calculated rates would be subject to approval by the Commission. He recommended that the rates thus calculated and approved be applied in both the 4(e) and the 5(a) proceedings, *i.e.*, to both suspended and future rates.

The Commission reversed the Examiner. Its decision and findings were also extended and exhaustive (82 printed pages, plus exhibits). One Commissioner dissented in re-
[fol. 415] spect to the computation of the cost of service; otherwise he concurred. Basically, the Commission concluded "beyond any doubt, that the traditional original cost, prudent investment rate base method of regulating utilities is not a sensible, or even a workable method of fixing the rates of independent producers of natural gas." It pointed out critical differences between pipeline operations and producer operations, quoting from opinions by Mr. Justice Harlan and Mr. Justice Jackson, and saying that in regulating producers it is faced with problems entirely different from those of an ordinary public utility. It pointed out that simply to allow producers a return on investment would penalize the efficient or fortunate and reward the inefficient or unfortunate. Only where a producer purchases a fully developed acreage at a fair price does his investment have a real relationship to his return. The producer who first takes the risk in an area and proves it productive pays less for his rights than those who come later. But he must invest his funds before he knows whether he will have anything to sell or not. Mr. Justice Jackson once wrote that "there is little more relation between the investment and the result than in a game of poker."

The Commission pointed out that a producer of natural gas also produces oil, the price of which is unregulated, makes sales (intrastate, etc.) not subject to Commission jurisdiction, and sells products also excluded. Thus "extremely difficult" problems of allocating costs are involved. It commented that none of the experts proposed allocations acceptable to other experts. "Ridiculous results will be reached among the great number of producers and owners of interests if costs should be the only basis for regulation." It referred to the fact that much of Phillips's

gas is purchased from thousands of independent producers whose rates are under percentage-type casinghead contracts, dependent on Phillips's rates. The interests of the [fol. 416] many royalty owners must also be considered. Another problem is the administrative burden of full cost rate cases for each of thousands of independent producers. Adherence to cost rate-base methods results in necessity for a full-scale company-wide cost study to determine the proper price in any one contract. At the time of this Commission decision 3372 independent producers had rates on file. Five hundred seventy producers were involved in 3278 proposed rate increases under suspension and awaiting hearing. Of eleven rate increase cases in which full hearings had been had and decisions rendered, ten showed the increases justified. A special problem prevented decision in the other. In the three 5(a) cases theretofore completed, the producers' prices were found justified. Rigid adherence to the rate-base method would in many cases price the producers' gas out of the market. "From the foregoing, it follows that effective regulation of the price of natural gas must be on some more manageable plan than the rate base method. Thus it is clear that the better method would be to establish fair prices for the gas itself and not for each individual producer."

Simultaneously with the foregoing opinion the Commission promulgated a "policy statement" setting forth rate guidance schedules for various producing areas. These schedules consisted of two rates prescribed for each of twenty-three producing areas throughout the country (except for two areas, for which only one rate was given). One rate was for initial service, *i.e.*, new contracts, in the area. The other was for increases in rates, *i.e.*, proposals for increases in existing contracts, in the area. For example, in the first area listed (Texas District No. 1) an initial service rate of 15.0 cents per Mcf was given and an increased rate level of 14.0 cents per Mcf. The Commission described its preparation of these schedules thus:

> "In arriving at the price levels for the various areas set forth in the appendix to this statement, we have [fol. 417] considered all of the relevant facts available to us. Such consideration included cost information

from all decided and pending cases, existing and historical price structures, volumes of production, trends in production, price trends in the various areas over a number of years, trends in exploration and development, trends in demands, and the available markets for the gas. Of necessity, we have not set forth the adjustments to these prices which must be made to take into account every possible provision of every contract which may affect the actual price, such as Btu adjustments, conditions of delivery, etc. The relevance of such adjustments to the basic contract price and the appropriate established price standard must be considered as each filing is made."

The proposed use of this list was described by the Commission as follows:

"* * * * These standards will serve as a guide to us and to interested parties in determining whether proposed initial rates should be certificated without a price condition and whether proposed rate changes should be accepted or suspended.

* * * * * * *

"These price levels, as announced by Appendix A attached to this statement, are for the purpose of guidance and initial action by the Commission and their use will not deprive any party of substantive rights or fix the ultimate justness and reasonableness of any rate level."[7]

In its opinion the Commission said further: "This schedule of prices is only for guidance and does not constitute any determination of just and reasonable rates and will not foreclose any person from justifying a particular rate in any area." The schedule is of maximum acceptable rates for gas from a given area, as opposed to rates [fol. 418] established for each rate filing by each producer after a full cost-rate base consideration of each rate so filed.

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[7] Statement of General Policy No. 61-1, Sept. 28, 1960, 25 Fed. Reg. 9578 (Oct. 5, 1960).

The Commission disposed of the consolidated cases before it in three parts. The first part consisted of the superseded rates of the prior periods ("locked-in" periods). The second consisted of the presently current rates and those to be in effect during the interim period from now until the newly proposed area-rate system is completely designed and put into effect. The third part consisted of rates for the future after the completion and inauguration of the area-rate system.

Before we consider these several dispositions in detail we must understand the problem with which the Commission was dealing. The rates proposed to be increased in these 4(e) proceedings[6] are not the rates of utilities in the traditional sense, such as pipelines. The rates here involved are the charges made by companies which buy or produce a product, process it to suit the requirements of a customer, and sell it to that customer under a contract. The product is procured from many different places, from Texas to West Virginia, from Louisiana to Wyoming. In its raw state it is of many different contents. Different customers require different terms as to the physical qualities of the delivered article, points and terms of delivery, and other factors. Hundreds of producers, hundreds of contracts, and thousands of rate filings are involved.

When we use the terms "cost of service" or "rate base" in this context, we must be careful of the meaning we intend. There is a system-wide cost of service. This would be, as the words indicate, a computation for the entire Phillips system. But even so it would not be a computation for all Phillips operations, because the Company has many operations, such as those in petro-chemical fields, and sales of all sorts of petroleum products, and many sales not [fol. 419] subject to federal regulation under present statutes. In fact the Company's gross income from sales of natural gas in 1955 was less than six per cent of its total gross income. So even a system-wide computation of cost of service for sales of natural gas subject to Commission regulation requires monumental allocations of many costs, such as exploration costs, taxes, administration expenses, purchases, extraction costs, sales of residue gas and liquids, and so on. Nevertheless such a computation was made.

The Examiner and also the Commission determined and used a system-wide cost of service. As found by the Commission the system-wide cost of service for Phillips's sales of natural gas subject to Commission jurisdiction in the test year 1954 was $55,548,054, or 11.309 cents per Mcf. But even the figure thus carefully computed was subject to adjustment for purchased gas costs, gathering taxes, and royalties. The same observations apply to the rate base on a system-wide basis. One was determined by the Commission.

Then, theoretically at least, there is a cost of service for each contract, if not for each rate, and so for each 4(e) proceeding. But nobody, so far as we are advised, contends that any such computations could be made with any meaningful results by any known method. The results of any such effort would be pure guesswork, involving a vast multiplication of the arbitrary allocations which would have to be made.

The Examiner did not attempt to make any cost-of-service determination on individual contract, rate, or case basis. He determined a system-wide cost of service, which gave him a nationwide average unit cost of 11.662 cents per Mcf. He then proposed that '[b]ased on the system-wide cost of service herein approved, as set forth in Appendix Table 12 hereof, Phillips shall calculate the 'maximum rate for 1,000-pound, sweet, dehydrated, and [fol. 420] gathered gas,' at such level that its application to the sales volumes delivered in 1954 under each and every one of the 1954 jurisdictional contracts, as adjusted for the approved delivery condition rate differentials, will produce total revenues roughly equal to such system-wide cost of service." He proposed further that "Phillips shall file with the Commission a statement of such 'maximum rate,' including a clear and detailed explanation as to the manner in which it was calculated, together with a list of *calculated rates* for all of its jurisdictional rate schedules then in effect." The Commission, as we have said, reversed the Examiner, treating the case, in effect, in three parts.

1. As to the first part of the problem, the 4(e) proceedings, dealing with suspended proposals now super-

seded, the Commission made system-wide conclusions as to jurisdictional sales and applied them to these cases. It found $45,568,291 of revenues against $55,548,054[8] cost of service. This showed a system-wide deficit of some $9,000,000 on jurisdictional sales of natural gas. The Commission noted that no evidence had been presented to show that the different rates in these different (4(e)) proceedings were unduly discriminatory or preferential, which notation, translated, means that any adjustment in these rates should be correspondingly proportionate in respect to each and all. The Commission applied the result of its system-wide calculations to each and all of the 4(e) proceedings and concluded that no refunds were due. Having thus ordered, it concluded ("terminated") the proceedings.

The Commission made no determination of the cost of service of each of these contract rates separately; it had no evidence before it upon which it could make such de- [fol. 421] terminations, and it was of opinion that such computations would be unworkable and foolish under the circumstances.

In these 4(e) cases, as we have pointed out, the Commission was dealing with a locked-in period. The revenues derived from the rates at issue had been impounded. The only question of substance in respect to that period was whether refunds should be made. The Commission decided that question, flatly and directly. No other question remained in those cases for decision. They presented no questions as to rates to be charged. Each presented the question whether a refund was due that customer for that past period and, if so, how much. Having made three determinations—(1) that there was a deficit of some $9,000,000 a year in revenues against cost of service, (2) that the increases involved totaled about five and a half million dollars and so, if allowed in full, would not wipe out the operating deficit, and (3) that any adjustments should be proportionate to all contract rates—it concluded that no refund was due on any contract, *i.e.*, in any 4(e)

[8] Modified to $54,525,315 after rehearing.

proceeding. Section 4(e) pertinently says that the Commission "may" order a refund of "the portion of such increased rates or charges by its decision found not justified." We cannot say that a deficit justifies or requires a refund or that the Commission was unlawfully arbitrary in reaching that result from the premises.

We think the Commission's course was reasonable and tenable. Surely, if only a single rate had been involved, and enough evidence were introduced to justify, under testing, a conclusion that the company was operating at a deficit under that rate, it would not be necessary that evidence be taken to establish the precise penny amount of the deficit in order to support a reasonable inference by the Commission that no refund was indicated. Of course, in the matter at bar a number of rates in separate cases were involved, but the principle of procedure and [fol. 422] the scope of permissible inferences from basic facts are much the same as in the suggested illustration. We think the facts support the conclusion.

It is argued that the Commission did not declare the rates under consideration to be just and reasonable or the contrary; that, instead, it "terminated" the proceeding. The contention is that the Commission made no decision. We think the point is not well taken. The Commission did make a clear decision, after elaborate findings, upon the one substantive issue before it. It did say it "terminated" the proceedings, but it terminated them after deciding the basic and dispositive issue, and it entered an order on that decision. Its "termination" was much like that of a judge after he has rendered findings, conclusion and judgment.

Whether the Commission should have preceded its ultimate conclusion of no-refund with an intermediate conclusion of justness and reasonableness in the rates at issue, and whether it properly added the termination order to its decisive finding, seem to us to be immaterial queries. The important feature is that the Commission reached and decided the critical substantial issue, rationally and upon detailed findings of basic facts upon an ample record.

This is not a *Minneapolis Gas*[9] situation, in which the Commission did nothing but simply terminated the proceeding without passing upon any of the disputed issues before it.

2. The case yields to clearer treatment if we next consider the part of the Commission's treatment which is last in chronological order, that is, the determination of rates [fol. 423] for the future. As to these rates the Commission embarked upon the formulation of a new method of fixing just and reasonable rates for producers. It inaugurated hearings for that purpose. We think we need not explore the possibilities of success in that venture, or stop here to describe the projected scheme previously outlined in this opinion. In general it is referred to as an area-price method; it aims to establish proper prices for the gas rather than for the seller thereof. The Congress has confided the regulation of the natural gas industry to the Commission, not to the courts. The Supreme Court has said several times that the Commission is not bound to any one method or to known methods. The regulation of gas producers is a new project. Obviously, as is cogently pointed out in this record, it presents new and complex facts and problems. It would be foolish for the courts to hold that the Commission is bound to apply to these new conditions the methods and measurements designed and used for other and different regulatory purposes. We think it is clear that the Commission had ample authority to embark upon an effort to design suitable new standards for use in the regulation of producers when it found that the tools at hand were not suited to this purpose. The Commission abandoned the pending 5(a) proceeding in which it had been endeavoring to establish rates for the future by methods it now deems inadequate. We see no reason why it should not have done so.

3. The difficult part of the case before us concerns the second, or middle, part of the Commission's disposition. This involves the rates for the period from 1959 until the

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[9] Minneapolis Gas Company v. Federal Power Commission, —— U.S. App. D.C. ——, 294 F.2d 212 (D.C.Cir. 1961).

new system—or a new system—is designed and established. This period will be long, estimates running from four to fourteen years. The rates during this period may, theoretically, be (1) rates in effect without increases having been proposed after January 1, 1959, (2) rates proposed to be increased since that date and suspended under Sec- [fol. 424] tion 4(e), (3) rates for which increases may be proposed after the present time; (4) initial rates, *i.e.*, rates under new contracts made after January 1, 1959.

To meet the need for interim regulation the Commission took several steps. It published the policy statement which we have described. That announcement contained several components. First, the Commission said that in determining its own *sua sponte* action in respect to rates (*i.e.*, suspending proposed increases or inaugurating inquiries into existing rates) it would be guided by the guide rates. Second, it said that persons attacking rates (*i.e.*, customers and consumers) would be required to present evidence as to the industry generally in the area concerned, as well as the traditional evidence relating to the individual producer involved. Third, it said that "[a]s experience and changing factors may indicate," it would change the areas designated and likewise change the guide prices. Fifth, it said it will use its guide rates in disposing of 4(e) (*i.e.*, suspended proposed increases) proceedings arising upon increases proposed since January 1, 1959.

Refraining from exploring the various arguments, and argumentative trails, pointed out to us by the parties, we come directly to the crux of this problem. Has the Commission power under the Natural Gas Act to do what it did? Can it adopt upon the basis of its own expertise and its files, without a record made in the open in respect to the specific subject matter in issue, and without hearing, a set of guide lines by which it will be controlled in its regulatory functions during an interim period while it is attempting to perfect a suitable system for permanent regulation? We think it can.

In the first place, and throughout, we must remember that the Congress has power to direct the regulation of interstate commerce, and it has placed that regulatory

[fol. 425] power over natural gas in the Power Commission. We must remember that the problem at bar concerns a regulatory power. We are not considering adjudicatory, or quasi-judicial, power. It has long since been established that rate-making is a legislative function, and it is so defined in the Administrative Procedure Act.

Regulation poses many difficult problems. New regulation poses acutely difficult problems. Solutions oftentimes develop slowly. Many illustrations of that fact could be called to mind.

What power has the Commission in respect to interim regulation while the permanent structure is being designed and erected? Must it use means and methods long established for use in respect to other and different regulatory necessities? Or may it design from its own judgment and accumulated data a new method designed for the new problem? The difference between a public utility, such as a pipeline rendering a service by means of a fixed plant and operation, and a producer, who discovers or buys a product where, when and under such terms as he may, and sells that product under contracts negotiated on the open market, are too evident to justify elaboration. Whether the method thus designed and put into use by the Commission is good or bad is not part of our problem. Our inquiry is whether it was within the orbit of statutory authority and whether it was within constitutional limitations. We turn to those questions.

The Natural Gas Act is broad in its bestowal of power. It declares that all rates demanded by a company in connection with the sale of gas in interstate commerce for resale shall be just and reasonable. Section 4(a). A gas company files with the Commission schedules of its rates. Section 4(c). If a company proposes to increase a rate, it must file a new schedule. The Commission may then enter upon a hearing concerning the "lawfulness" of the [fol. 426] proposed rate. Section 4(e). If the Commission, on its own motion or upon complaint, finds a rate unjust, unreasonable, unduly discriminatory or preferential, the Commission "shall" determine the just and reasonable rate. Section 5(a). Of course, constitutional restrictions apply; rates fixed by governmental authority cannot be confisca-

tory; all procedures must be by due process, that term conveying meanings differing according to the basic nature of the proceeding but always including that which is fair and decent according to the standards of our social order and time.

The statute contains no definition of a "just and reasonable" rate. It is established by tradition and by many court decisions that for a public utility, rendering service by use of fixed equipment, a just and reasonable rate is one which returns a fair profit upon the investment, or which supplies the utility with adequate revenues to command needed funds upon an economically reasonable basis. But what of a fair price for a commodity bought and sold by a merchandiser? Almost the whole of the economics of merchandising differs from the economics of public utility service. Are the just and reasonable prices of such a merchandiser limited to fair returns on his own investment and prices paid by him (and, if so, what investment and what prices), or are those prices reasonably measured by the fair prices for the product as measured by the open competitive market for the product, evaluated by Commission expertise and data on the whole of the market operation? Either criterion is a method of regulation. It seems to us that the choice must lie with the Commission.

Let us emphasize that we do not have before us at this time the question whether any rate set by the Commission as a guide rate falls within the area of reasonable computation. That question is emphatically left open [fol. 427] by the Commission, and by us, for consideration when some one or more of the selected guide rates is attacked, by a producer, a customer, or a consumer. The problem here at this time is merely whether the Commission may embark upon this method of regulation. Since it is the Commission's judgment that this method is best suited for the regulation of these prices, for the determination of their justness and reasonableness, we find in the statute nothing to deny a trial of the method.

Of course, conceivably, justness and reasonableness from the standpoint of the consumer might be defined as limiting the vendor's return to a fair amount on his investment, and his price accordingly. But, if the government

agency charged with the responsibility in the public interest finds, after elaborate accumulation of data, that such a measurement is unworkable, may not a fair price for the product reflected on the open market, after scrutiny and adjustment by the government agency concerning the factors which produced that price, be just and reasonable for the consumer? Of course the agency would be required to be alert for artificial impulses in such a fair area prjce, and the avenues of attack by consumers would have to be kept open without obstruction; but, if the latter is avowed, how could we assume in advance that the agency would not protect the consumer as it is charged by the Congress to do? The Commission is not here proposing to accept a field price, or any other price as is. It has announced guideline rates which it deems to be, on the basis of the internal data in its files on all the operators in the several areas, fair rates for the product in those areas. Such rates, thus determined, would seem to be just and reasonable rates for the consumers of the product. And, similarly, they would seem to be just and reasonable charges for the producers to make.

As to the constitutional question of confiscation, it [fol. 428] would seem to us that the question should await the proof presented by a producer in respect to a particular rate in a particular area.

Thus we come to conclude that the interim method of regulation proposed by the Commission does not appear at this point in the process to be violative of either statutory or constitutional limitations.

It is urged upon us that the Commission has abandoned regulation of these rates for this interim period. We do not agree with that view. It has certainly changed the method of regulation, or, more precisely, the standards by which it will apply its regulatory power. It has abandoned case-by-case, contract-by-contract measurements on a cost-of-service rate-base basis. It has installed an area fair price measurement for the prices of the product to be sold. In so doing it has abandoned a method it finds to be unworkable and foolish in favor of a method it deems to be workable and just and reasonable. If that be so, instead of abandoning regulation it is making regulation

effective. The choice it faced, at least in its own view, was not between regulation or no regulation but was between effective and ineffective regulation.

If, as some consumer interests fear, the new process turns out to be ineffective in the protection of their interests, the way is open for them to challenge the results; as we have pointed out, that way must be kept open. New rates and increases in rates proposed during this interim will be subject to suspension and refund, and so the rights of customers will be fully protected. The new method will also apply in 5(a) proceedings to any existing rate found to be unjust or unreasonable. Refunds cannot be ordered in the latter cases and so consumers bear the disputed rates during the period of the inquiry. But this same situation obtains in the present process of regulation; the application of the new criteria makes no change [fol. 429] in this procedural aspect. In the case at bar the Commission has found, after elaborate consideration, that present rates result in deficits to the Company. Consumers have no tenable ground for complaint of such rates. So it seems to us that the interests of consumers are amply protected during this interim period; at least a contrary effect should await the event for us to disturb the view of the Commission, based as it is upon this record.

There remains for discussion a point concerning two 4(e) proceedings which were not terminated. They involved proposed increases based upon escalator clauses in two of Phillips's contracts. These contracts were made before producers such as Phillips were subject to regulation. They were with pipeline companies, as customers, which were subject to regulation. The contracts provided that, if the pipeline companies were granted increases in the rates they could charge, Phillips in turn would receive increases in the rates it charged these customers. These customers had proposed increases, and they were pending in 4(e) proceedings. The Commission ordered that upon decisions in the customers' rate cases Phillips's cases would be acted upon.

Wisconsin and California contend that the Commission should now declare these escalator clauses to be illegal and void as against public policy. As a matter of fact the

Commission has declared these clauses to be against the public interest and that they should be held inoperative. But, the Commission says, in so far as these cases of Phillips are concerned, action of the sort demanded by Wisconsin and California is premature. Action on these clauses, it says, should await action on the pending cases which in orderly processes present the problem for decision. We agree with the Commission.

Affirmed.

[fol. 430] FAHY, Circuit Judge, dissenting, with partial concurrence: I am not able to agree that the order of the Commission terminating the section 4(e)[1] and section 5(a)[2] proceedings should be affirmed. I think the cases should be remanded to the Commission for decision.

While the Commission advances strong reasons for abandoning cost of service as a method of determining the justness and reasonableness of the rates of independent producers of gas, a careful reading of the Commission's opinion demonstrates that the Commission's conclusion that such a method is unworkable follows from a generalized view of the problem of producer rates rather than from the inability of the Commission to utilize the cost of service method in these Phillips cases.

Embarkation upon the area method preferred by the Commission does not necessitate judicial intervention, certainly not at this time; for judicial review must await a Commission order based upon that method. We should not seek to deter the Commission from pursuing such a method in future proceedings, or from using it in any proceedings already initiated along those lines. But it does not follow in my opinion that the Commission should be affirmed in failing to decide the present cases, though it may need to update the record. In the same breath as it were in which it describes the unworkability of the cost of service method the Commission itself accepts that pre-

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[1] 52 STAT. 822 (1938), 15 U.S.C. § 717c (1958).

[2] 52 STAT. 823 (1938), 15 U.S.C. § 717d (1958).

cise method in finding that no refunds are to be required in the section 4(e) proceedings, stating:

> While we have found that the rate base method is not an effective means of regulating the producers' prices, evidence in this proceeding was presented almost entirely upon the cost basis and, of course, there were no ceiling prices issued by us at the time of the hearing. There was some field price evidence intro- [fol. 431] duced, but if field prices could be employed in arriving at rates for Phillips, the evidence was incomplete and unrepresentative of Phillips' diverse sales. Therefore we shall proceed on the basis of the evidence adduced in this case to reach conclusions, as reasonable, intelligent and logical as possible even though we know and have herein stated the difficulties inherent in determining a cost of service for Phillips using the rate method. This is clearly a lawful way to determine rates for Phillips as illustrated by the *City of Detroit* case,[11] and under the present record is the only possible method, and therefore we shall make every effort to reach a result by this means.
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> [11] *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC), *certiorari* denied, 352 U.S. 829.

The Commission could as well have proceeded, with supplemental data, to decide the question of justness and reasonableness of the rates in the section 4(e) proceedings, and, also, to have determined under section 5(a) the just and reasonable rates to be thereafter observed and enforced.

This view is strongly fortified by the able decision of the Presiding Examiner. After an illuminating analysis of the voluminous record made on a cost of service basis he was able to propose definitive decisions. The record had been made with the cooperation of all parties, Phillips itself affirmatively acquiescing in the position that cost of service was the appropriate basis on which to proceed. Phillips' position, as the Examiner points out, was that its jurisdictional rates should be determined upon the basis of an overall cost of service.

It is one thing to say, as the Commission does, that the area method should hereafter be adopted, or even adopted in other cases which have not proceeded as far as those before us. It is quite another thing to say that the latter should not be decided under the standards of the Act because the area method was not used in preparing the record. Unless decided Phillips' challenged rates are left un- [fol. 432] determined under the standards of the Act since 1948, and apparently will continue to remain undetermined until some future day when new proceedings, now in an inchoate status with no end in sight, are concluded. Difficult and complicated as the tasks of the Commission admittedly are I cannot agree after reading the Examiner's decision or the Commission's findings that the congressional mandate of section 4(e), which requires that these matters shall be decided "as speedily as possible," is being complied with, or that the responsibilities of the Commission under the Act are discharged in the situation resulting from the termination order.

These cases need not be treated as if they were ventures initiated in search of an ideal method of regulating the rates of independent gas producers. Having in mind the history of these proceedings, and the primary congressional purpose of consumer protection, it seems to me that decisions on the present record, supplemented as may be found to be reasonably necessary, would be far more likely to approximate fulfillment of the purposes of the Act than are the termination order and the resulting situation.

The Commission says it has a discretion to terminate as well as to initiate; but once it has exercised its discretion to initiate and has pursued the matter to the extent we find here its discretion to terminate is not as broad as was its discretion to initiate. The former becomes limited by the conditions existing at the time of its exercise. *Minneapolis Gas Co.* v. *Federal Power Comm'n*, —— U.S. App. D.C. ——, 294 F.2d 212. Compare *Eastern Air Lines, Inc.* v. *Civil Aeronautics Board*, —— U.S. App. D.C. ——, 294 F.2d 235.

The Commission has actually found Phillips' cost of service on the basis of the record made and has arrived on the same record at a proper rate of return, stating

"this is clearly a lawful way to determine rates for Phil-[fol. 433] lips as illustrated by the *City of Detroit* case, . . . and under the present record is the only possible method . . ." In this manner the Commission has come so close to doing what it says it should not do as to demonstrate that it is able to do what it has failed to do.

The finding of the Commission in the section 4(e) proceedings that there could be no refunds because the cost of service exceeded the revenues on the basis of the data for the 1954 test year, I think does not justify the order terminating all but two of the section 4(e) proceedings, or the Commission's invitation to Phillips to move to terminate all others which are still pending. The absence of a decision on the issue of justness and reasonableness of rates has the effect of leaving all rates subsequent to 1954 untested under the standards of the Act. Substance is not achieved merely by finding whether or not refunds were due on the basis of the 1954 data. A finding in that regard should not be independent of a finding of the just and reasonable rates. The former should follow from the fact that the just and reasonable rates are not exceeded by those in effect.

The decision of these cases under the standards of the Act not only would not preclude the Commission from embarking upon the area method, but it also would not preclude the Commission from correcting or modifying the decision should the area proceeding show such correction or modification to be desirable; nor do I think a decision on the present record, supplemented as may be needed, would preclude the Commission, pending conclusion of an area proceeding, from establishing guides, formulated, however, with the aid of a decision in the present proceedings.

I agree with Judge Prettyman as to the prematurity of the request for action on two section 4(e) proceedings which have not been terminated.

[fol. 434] [File endorsement omitted]

IN UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 16175

STATE OF WISCONSIN and PUBLIC SERVICE COMMISSION OF WISCONSIN, Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, Intervenor.

No. 16177

LONG ISLAND LIGHTING COMPANY, et al., Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK, Intervenors.

No. 16180

PEOPLE OF THE STATE OF CALIFORNIA and PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, Petitioners,

v.

FEDERAL POWER COMMISSION, Respondent,
PHILLIPS PETROLEUM COMPANY, Intervenor.

On Petitions for Review of Order of the Federal Power Commission

Before: Prettyman, Fahy and Danaher, Circuit Judges.

JUDGMENT—November 30, 1961

These cases came on to be heard on the record from the Federal Power Commission, and were argued by counsel.

On Consideration Whereof, It is ordered and adjudged by this court that the order of the Federal Power Commission on review in these cases is affirmed.

Per Circuit Judge Prettyman.

Dated: November 30, 1961.

Separate dissenting opinion by Circuit Judge Fahy, with partial concurrence.

[fol. 439] Clerk's Certificate to foregoing transcript (omitted in printing).

[fol. 440]

SUPREME COURT OF THE UNITED STATES

No. 754, October Term, 1961

WISCONSIN, et al., Petitioners,

vs.

FEDERAL POWER COMMISSION, et al.

ORDER ALLOWING CERTIORARI—May 14, 1962

The petition herein for a writ of certiorari to the United States Court of Appeals for the District of Columbia Circuit is granted. The case is consolidated with Nos. 755 and 756 and a total of three hours is allowed for oral argument.

And it is further ordered that the duly certified copy of the transcript of the proceedings below which accompanied the petition shall be treated as though filed in response to such writ.

Mr. Justice Frankfurter took no part in the consideration or decision of this application.

[fol. 441]

SUPREME COURT OF THE UNITED STATES

No. 755, October Term, 1961

CALIFORNIA, et al., Petitioners,

vs.

FEDERAL POWER COMMISSION, et al.

ORDER ALLOWING CERTIORARI—May 14, 1962

The petition herein for a writ of certiorari to the United States Court of Appeals for the District of Columbia Circuit is granted. The case is consolidated with Nos. 754 and 756 and a total of three hours is allowed for oral argument.

And it is further ordered that the duly certified copy of the transcript of the proceedings below which accompanied the petition shall be treated as though filed in response to such writ.

Mr. Justice Frankfurter took no part in the consideration or decision of this application.

[fol. 442]

SUPREME COURT OF THE UNITED STATES

No. 756, October Term, 1961

LONG ISLAND LIGHTING CO., et al., Petitioners,

vs.

FEDERAL POWER COMMISSION, et al.

ORDER ALLOWING CERTIORARI—May 14, 1962

The petition herein for a writ of certiorari to the United States Court of Appeals for the District of Columbia Circuit is granted. The case is consolidated with Nos. 754 and 755 and a total of three hours is allowed for oral argument.

And it is further ordered that the duly certified copy of the transcript of the proceedings below which accompanied the petition shall be treated as though filed in response to such writ.

Mr. Justice Frankfurter took no part in the consideration or decision of this application.